JOINT IEPR AND ELECTRICITY & NATURAL GAS
COMMITTEE WORKSHOP
BEFORE THE
CALIFORNIA ENERGY COMMISSION

In the Matter of:	)	
	)	Docket No.
Natural Gas Supply under	)	
Uncertainty Shale Gas, LNG and	)	
Pipelines/Infrastructure	)	

CALIFORNIA ENERGY COMMISSION
HEARING ROOM A
1516 NINTH STREET
SACRAMENTO, CALIFORNIA

THURSDAY, MAY 14, 2009
9:00 A.M.

Reported by:
Phillip Gioe

COMMISSIONERS PRESENT

James D. Boyd, Vice Chairperson, Associate Member, IEPR Committee; Electricity and Natural Gas Committee

ADVISORS and STAFF PRESENT

Leon Brathwaite
Robert Kennedy
Suzanne Korosec
Ruben Tavares
Bill Wood

ALSO PRESENT

Terry Engelder, Pennsylvania State University
Leslie Ferron-Jones, TransCanada
Marty Kay, SCAQMD
Amy Mall, NRDC
Richard Myers, CPUC
Don Petersen, PG&E
Gordon Pickering, Navigant Consulting
Tom Price, El Paso
Kevin Shea, Sempra Energy
Wayne Tomlinson, El Paso
Scott Wilder, Sempra Energy

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P R O C E E D I N G S

9:00 A.M.

MS. KOROSEC: -- both represented today by Commissioner Boyd. Just a few housekeeping items before we get started: restrooms are out the double doors and to your left, there is a snack room on the second floor of the atrium at the top of the stairs under the white awning; and if there is an emergency and we need to evacuate the building for any reason, please follow the staff outside to Roosevelt Park, just kitty corner to the building, and wait there for the all clear signal.

Today's workshop is being broadcast through our WebEx conferencing system. And for parties who are using that system and would like to ask a question or speak during one of our two public comment periods today, you can use the "raise hand" feature or send a chat directly to our WebEx coordinator.

Just to provide a little context for today's workshop, the Energy Commission is required by statute to develop an Integrated Energy Policy Report, or IEPR, every two years. It provides an overview of major energy issues and trends that are facing California's energy markets, and also provides policy recommendations to help the state meet its energy goals.

Natural gas obviously plays a crucial role in our Energy markets; it supplies about a third of the state's total energy requirements, and it is particularly critical in the electricity sector, with about half of the natural as we use going toward electricity generation.

In the Scoping Order for the 2009 IEPR, the IEPR Committee directed staff to look at gas supplies over a 10-year horizon, including natural gas basins, pipelines, proposed LNG facilities, and delivery infrastructure.

So consistent with that direction, today's workshop is going to provide an update and seek public comment on (1) natural gas pipelines and infrastructure, (2) the production of shale gas, and (3) liquefied natural gas.

We will have two opportunities for public comments, the first after the morning session and the second following the afternoon session. For parties in the room who wish to speak during the public comment period, it is helpful if you fill out a blue card with your name and employer, these are out on the table in the foyer, and you can give those to me throughout the day. And when you do come to speak, it is also very helpful if you could provide a business card to our court reporter so we can make sure your name is spelled correctly in the transcript.

So with that very brief introduction, Commissioner Boyd, I will turn it over to you for opening comments.

COMMISSIONER BOYD: Thank you, Suzanne and thank you for your comprehensive background notice. Those of you who are familiar with us at the Energy Commission and the Integrated Energy Policy Report recognize that, in the past, there can be sometimes over 60 public workshops and hearings for us to compile the information we need to, to be able to introduce that report. Mr. Byron and I constitute the Integrated Energy Policy Reporter for this 2009 Report, as mentioned. We also happen to be the Electricity and Natural Gas Committee for the Commission, and Commissioner Byron was seen two short minutes ago wheeling away from this building on his Segway, as he headed for another part of town to chair yet another Integrated Energy Policy Report Committee on a different subject, Electricity and Smart Grid, so we are doing double duty today, and so you have got me for the duration and I constitute the representation for the two committees.

With that, I would just say most of you are probably familiar with the Integrated Energy Policy Report, it has been with us ever since the electricity crisis hit California and the Legislature and, you know, I think one of its very brilliant moves that altered this integrated assessment of energy in California, and provided us a forum for keeping up with all the various energy subjects. Natural Gas is the subject that not only have I followed for the almost seven and a half years I have been here as a Commissioner, but the two to three years before that, there are some very familiar faces in the crowd who were part of the small working group that, when the electricity sky started to fall on California, recognized that Natural Gas was a key component of that issue and have been following the subject ever since. I, as well as others, are very impressed with the agenda that the staff put together for today. I am really appreciated of all of you who have come to share your knowledge with us. It has proven to be a very interesting, if not difficult, arena to operate in and, on my short watch in this area, we have gone from feast to famine to feast again, as it may relate to Natural Gas availability, just depending on what type of medium it was going to be when it got to California, and how it was going to get to California. So I am certainly interested in hearing what is the latest so we can try to reflect that in our Integrated Report to give good policy advice to our Governor and to our Legislature, and to those who are interested about the subject in the future. And we cross our fingers every time we do this because nobody is ever really correct when it comes to this arena. But we try to do the best job we can; we think we do a pretty decent job.

So with that, I look forward to the staff presentations and, again, I thank you all for being here. You are going to contribute to an interesting year in looking at the subject of Natural Gas. And the last thing I will comment on is, as a very strong advocate of the use of Natural Gas in transportation sectors, as well as just in the industrial boiler sector, I am going to be keenly following this area, I think, as California works very hard to alter its portfolio of transportation fuels; Natural Gas has again risen to near top of the list, if not permanently as transportation fuel, accepted by everyone. Even the Energy Secretary has said that Natural Gas is the bridging transportation fuel for our future, so it is something we want to pay a lot of attention to. So thank you, all. And with that, I guess, Ruben, I am turning it over to you. Oh, Ruben, I rudely forgot to introduce -- on my right is Susan Brown, who also has followed the subject for a long long time. So we constitute the representation of the Executive Floor.

MR. TAVARES: Yes, good morning, Commissioner. Good morning, Susan. For the record, my name is Ruben Tavares and I am part of the Commission staff. Today we have a series of presentations by Commission Staff and other outside experts in three areas. The three areas that we are going to be covering today are shale gas production, liquefied natural gas (LNG), and also Pipeline and Infrastructure.

The staff prepared three papers that were posted on the Web, and the purpose of the papers was to explore a professional outlook on key uncertainties surrounding these three areas, including also the environmental impacts. We have raised several questions in the Notice of the Workshop, soliciting input and comments from experts to the lay industry. Also, we do not expect to solve all of the uncertainties today in these three areas; hopefully by the end of the day, we will have a more complete picture of shale gas production, energy, and the pipeline infrastructure.

If Commissioner Boyd permits, we would like to start presentations first, and then we will follow with outside experts to make theirs. We would like to have public comments, one in the morning, and one in the afternoon. All presenters have approximately 25 minutes to make the presentations. One thing I would like to ask the

Commissioner, if he permits, is that, right now in our Notice of the Workshop, we are requesting the comments by May 22nd. We would like to extend that deadline to June 5th, given that some presenters today actually are asking for an extended period of time. So if you agree, Commissioner, I would like to ask for that.

COMMISSIONER BOYD: Well, it is good for you to impute so much power to a Commissioner. I am actually looking at Suzanne hiding in the doorway there. If she says it is okay, then it is okay. She is the Program Manager for the entire IEPR. Apparently you have got the green light, Ruben, so I would be glad to concur on the extension of that date.

MR. TAVARES: Okay, Commissioners. The natural gas --

MS. KOROSEC: Bear with us for just a moment, we are using a WebEx system.

COMMISSIONER BOYD: This is my second frozen computer experience of the day, this is not good. My early morning breakfast meeting was interrupted by a frozen computer.

MS. KOROSEC: There we go, we have got it. Okay.

MR. TAVARES: Okay. The North American Natural Gas market of the last 20 years has gone through several stages. None of those stages are sequential, but more or less, you know, we had five stages. Since 1990, we had an increase in natural gas production in North America. On the second stage, we had, again, given some concerns raised with greenhouse gas effects, we had a substantial demand increase of natural gas. Then, on the third stage, we had an increase, again, an accelerated increase in natural gas production that actually peaked around 2001. Given those two aspects, the supply increase, but also the great demand increase in natural gas, we had some problems with the supply, and then LNG apparently came to the rescue. However, in the last few years, couple years, we are having some difficulties in actually licensing LNG facilities, and bringing LNG to the United States.

So what is next? We have seen an increase, tremendous increase, in shale gas production. So we are going to go through these five stages as we move on. Again, in the 1990s the outlook for natural gas supplies was very optimistic in the lower 48 states, and including there was a lot of hope for developing the Alaska North Slope. There was very strong production from the WCSB and also hope that we will bring gas from the McKenzie Delta. Even Mexico was looking very strongly at natural gas from the workers in Northern Mexico. Again, prices were very stable, very low, about $2.00 for a thousand cubic feet through the '80s and '90s.

Now, this graph shows those stages. As we can see, in 1990 we see the increase in natural gas, again, all the way through the year 2001 when we had the peak. Prices, again, in the $2.00, no more -- we had a few spikes here and there, but mostly in the $2.00 to $3.00 per thousand cubic feet, until we had the crisis here in 2001. Again, there were some initial concerns about greenhouse gas effects, and we turned to natural gas to replace the use of high carbon fuels such as coal and petroleum. Mainly, this increase occurred in the gas power generation; in fact, the National Petroleum Council in the 1999 study projected 110 GWs of new capacity by 2010, but in a revised study, the agency in 2003 actually expected not just 110 GWs, but 200 GWs by 2005 instead of 2010. Again, we can see here the natural gas demand increasing from 1990 and continuing to increase in Mexico -- actually, Mexico not that much, not in Canada, but in the United States, especially because of the power generation area. In this graph, we can see the increases in the United States in demand by sector, residential sector pretty flat, also the commercial, and we can see some actual decline in the industrial sector, but in the generation sector we can see those increases occurring. Domestic natural gas production actually peaked, and there was some, as we all know, delays in construction of the pipelines coming from Alaska's North Slope and the McKenzie Delta. Given these delays, there was an increased consumption from the lower 48 states and also from the Western Canadian Sedimentary Basin. And domestic production actually peaked in 2001. However, there was a steep decline in production mainly from the Gulf of Mexico. And we can see here that phenomenon. This is mainly the area where we have a tremendous decline in production of natural gas. Most of all the areas remain pretty stable, and actually we are seeing some increase in the Mid-Continent area. And we suspect that this is because of the unconventional gas, shale gas production.

In the United States, the average well production actually declined, as you can see, from 160 cubic feet per well in 1989 to approximately 100 in 2007. At the same time, you know, the amount of producing wells increased tremendously. In Canada, we also saw this production of natural gas in the Western Sedimentary Basin basically stable and lately actually declining. And, again, we saw the same phenomenon in Canada as we saw in the United

States of this increase, actually decline in production per well, and the increase of the number of wells, actually drilling and producing wells, in Canada.

So after all of these issues and increase in demand, and actually lower, somehow the supply of natural gas in the United States and even Canada and Mexico started looking more into importing LNG into the United States. Actually, the United States has imported LNG since the 1970s; in fact, in 1979, the U.S. imported about 253 Bcf from Algeria, and have been importing from Algeria ever since -- not that same amount, but a lower amount. However, in 2000 LNG imports accelerated, and in 2007 actually peaked at 770 Bcf. And we can see this pattern here since 2003, where we have been importing approximately one and a half to two Bdf since 2003, and in 2007 it jumped up to three or beyond three Bcf per day. However, in 2008 we saw the decline in the importation of LNG.

So what do we have as far as LNG? In order to make up, we have approximately 12 Bcf of existing LNG regasification capacity, we have 8 Bcf per day under construction, 24 Bcf per day approved by regulators, and another 30 Bcf of potential LNG. We can see those numbers more or less in this graph; again, about 12 Bcf existing in the United States, and actually North America, United States and Mexico.

So what do we have next? The lower 48 states consume approximately 62 Bcf per day, or approximately 22 Tcf per year. California consumes 6.3 Bcf per day, or approximately 2.3 Tcf per year. The price of natural gas has increased through the 2000s; again, it went from about $2.00 to $4.00, $5.00 and we saw actually in July of last year that it reached about $13.00 per million Btu. At the same time, we have seen a lot of research and development in the unconventional gas areas such as coal and shale gas production.

The production of unconventional gas has accelerated and, in fact, in 2007, from 2007 to 2008, it increased by nine percent. Yesterday, we had at FERC -- actually, FERC provides a briefing every month, and they indicated that they saw an increase of 14 percent of shale development, so that is very significant. Again, at the same time, LNG imports have declined and some of the applications and development of LNG facilities here in California have some difficulties.

And we can see these increases in prices that I just mentioned kick in -- actually, we have some spikes in here, but from the $2.00, it increases slowly through the years to $4.00, $6.00, $8.00, and, again, up to $13.00 in July of last year. This graph also shows some of the increases in shale gas and, as you can see, the increases are very dramatic. And, again, today we will have several speakers who are going to be talking about this shale gas production.

So what is next for California? California imports about 87 percent of gas needs. I mean, we need to import about 87 percent, and we produce only about 13 percent, but it is production essentially declining. We have been stable, but not increasing at all. Would shale gas and other unconventional gas production continue to increase? There are some estimates that we have in the United States, and even North America, up to 800 Tcf of existing shale recoverable reserves. And there are some estimates even higher than that, so we will find out today what other speakers have to say about shale as development. Will LNG be a part of the supply mix? We do not know. The prices in other countries seem to be pretty high and they are attracting a lot of those cargos; however, of the last couple months, we have seen actually some prices compatible to the prices in the United States. We need additional infrastructure to accommodate some of the LNG or some of the shale gas that will be developed here in North America; however, we also have to consider what the impacts are going to be on the environment, especially in the case of shale gas on water quality.

So with that, I would like to proceed to introduce some of the other speakers. But if you have any questions, Commissioner, I would be happy to answer.

COMMISSIONER BOYD: Ruben, a quick question. It really goes all the way back to your Slide 6, but you do not need to display it, necessarily. You just mentioned the study projections of the MPC in terms of GWs of electricity demand, and you had them projecting in the revised 2003 study 200 GWs by 2005. You do not happen to have the number that was actually realized in 2005, do you?

MR. TAVARES: I do not have the actual number, but the projection section was based on a lot of research that they did, and they were looking for -- it was only a two-year span between the study and the projection. I mean, they were projecting by 2005, 200. So although I do not have the numbers myself, I suspect that they have a very strong inkling that it was going to be a fact.

COMMISSIONER BOYD: Okay. I think it is a number we should dig up later for reference, but thank you.

MR. TAVARES: Okay. Thank you. Okay,

Commissioners, well, next we have Leon Brathwaite and he is a staff member, and he is going to be presenting Shale Gas Production paper.

MR. BRATHWAITE: Okay, good morning everyone, Commissioners. Susan, good morning. I hope everybody is doing fine and found your way here without any problems.

COMMISSIONER BOYD: So far, so good, Leon.

MR. BRATHWAITE: So far, so good. Well, I am glad to hear that, Commissioner. I was very worried there for a while. Anyway, this morning -- well, before I go on, I am Leon Brathwaite. I work here at the Commission. Some of you guys know me. Maybe some of you guys do not want to know me, but, I am here. Anyway, this morning I will be talking about Shale-Deposited Natural Gas, and I will look at a review of potential. As you know, in the popular press, shale has become such a big issue. Everybody thinks that shale is something that was just recently discovered yesterday, it is not. Shales have been produced in natural gas for the longest while in the United States. As a matter of fact, I think somebody said that the first shale well was in 1821, I believe, when Thomas Jefferson was probably still alive. But anyway, that is not a joke, it is true. So what I will do today, though, is to try to put some context to all of this, and to let you see why shale has become such a big deal. So without further ado, let us get into my presentation.

So what are the topics I will be talking about? Of course, I will tell you what shale formations are. We will look at the technological innovations and what I have called enhanced productivity. We will look at the locations of the shale. We have shale all over the United States, all over the lower 48 and Canada. We will look at that. We will look at the production history. Ruben pointed out that a little bit in his presentation. We will look at the reserve potential. We will also look at potential in Canada. And then we will talk about some of the uncertainties surrounding the development of shale.

Okay, so what is shale? Shale is really a sedimentary rock formation, and it is very organic-rich, meaning there is a lot of old dead creatures in there that have been transmodified, okay? That is what I mean. It may sound like a big word, but it is not. It is organic-rich. But in the past, shale has always been thought about as something that is used as a formation that is used to trap and seal the natural gas-bearing water formations like sandstones and limestones. But what has happened recently is that technology has changed that, where the shale now is acting both as a seal and as a productive formation, and this is what the big issue is about the shale. Now, the shale is nothing new, we have always known for the longest while that there is a tremendous amount of gas existing in the shale, we have always known that, I mean, throughout the life of the oil and gas industry. What has always been an issue is how do we extract it, and that has always been the issue, and we have only now in the last 20 years come up with the technology to do so.

Now, the shale can store gas in three ways, 1) it can be stored as free gas in the micro-factures, with the tiny little fractures that are within the shales, or they can store it in the minute pores of the shales. But the third way which really presents a real challenge to the industry is it can be stored as absorbed gas. And 25-85 percent of the gas that is in shales is stored in this manner. But what absorbed gas is, is that those methane molecules attached themselves to the organic material. I told you a little while ago that the shales are organic-rich. The methane molecules attach themselves to the organic material within the shales, and they are then concealed, or surrounded by some solid matter. This presents a serious challenge to the production of natural gas from the shales.

But before we get deep into the presentation on some of the issues surrounding the shales, I want to take a step back and talk about the requirements for economic production. And this is true whether we are talking about shales or we are talking about carbonate limestone, or sandstones. We have three requirements that we need, 1) we must have a significant deposit, and when I say "significant", I mean it must be big enough for the industry to want to go after it, okay? So they are not going to go after one and see if it is gas, all right? You need something big, something that could make them some kind of money. Secondly, you need significant, or sufficient, I should say, porosity, meaning that there must be some mechanism by which the gas is held, some storage mechanism. And third, you need some effective permeability, that is the ability for the gas to flow. Now, if you look at the little schematic I have here, this is a Wellbore, and what happens is that there must be some method by which the gas can come from the formation into your Wellbore, and then travel to the surface. Now, all three of these requirements must be present, the deposit, the porosity, and the effective permeability, all three must be present in order to have economic production.

The problem with the shales in the past, is that it had little or no effective permeability. That is the gas that will store, the tremendous amount of gas that was stored within the shales, had little or no ability to flow from the formation, into the Wellbore, and then to the surface.

And this is where technology came in. Technology changed all that. And where did we find all the technological innovations? In three areas, the first of which was exploration. So what happened is that you have now developed three-dimensional and four-dimensional seismic, and this has enhanced the capability to delineate the limits of all deposits. So now, instead of the industry looking at two-dimensional slices of the sub-surface, they are now looking at three-dimensional trunks (phonetic), so they can better delineate the extent of the deposits. The other innovation that we have had is in drilling. In the past, we have used, or the industry, I should say, has used quite a lot of vertical wells, but now, in the shale, in particular, we are now using horizontal wells. What that has done is that it creates a significant amount of contact with the formations of interest. So if I may go to my diagram on the next slide, you will see, previously when we were using those vertical wells, we only had this much, and if this yellow here is our formation of interest, we had this much contact, that much contact with the formation, from here to here. Now, with the horizontal well, which is shown here to your left, we have now expanded the contact this much. So now we have horizontal wells giving us five to 20 times more contact with our formation, and this has really helped boost production rates and ultimate recoveries.

The other innovation we have had is in well completions. Now, one of the things that is used, one of the stimulation techniques that is used in the shale, and have been used in the past, is hydraulic fracturing. Now, what hydraulic fracturing is, is just what they do is they take sand off some of the properties, mix it up with some liquid, they pump it into the formation, and they crack the formation open. And they leave the sand in there, and the flow blocks the liquid, and when the sand settles out, and everything is all set and clear, the fluid in the wells will produce at tremendous increased rates. And that is what hydraulic fracturing is. But in the past, we used to just do one zone at a time, but now we are doing multi-stage fracs. That means, and if you look at this schematic here, this is the horizontal portion of the well, and you can see what has happened is you create a network of artificial fractures, all along that horizontal portion of the well. In this particular case, you may have like seven different points where we have administered the fractured treatment, and you have a whole network, you are creating contact within the formation. This has raised the effective permeability and that effective permeability has caused the rest of these wells to change tremendously as opposed to when we were doing it with just the vertical wells.

So what happens? These techniques have boosted recovery rates, both in terms of its initial production, and in terms of the ultimate recovery. So where are the shales located? Well, if you look at this map, and this came from the EIA, you can see that the shales are located all over the lower 48, the Marcellus shale which is supposed to be the biggest of all shales, which is not yet even -- serious development has not yet even occurred in this shale as yet. But you can see it extends all the way from New York, all the way down here in parts of Ohio, and all over the place. I mean, that shale is huge, it is beyond belief.

We have the Barnett shale which is, of course, the most developed of all the shales. Most of the information and the data that we have about the shales today, and all these technological innovations that have been administered, a lot of that information has come from the Barnett. We have the Haynesville, which is supposed to be bigger than the Barnett, we have new things going on in Eagleford, going on in southern Texas, up in the Rocky Mountains area, we also have a bunch of shale activity going on there. One of the things that you will notice from this schematic is, on the West Coast, there is nothing shown here on the map. But there are two shales that have been identified here in California, the Monterey shale and the Macule (phonetic) shale. But there is no activity and no drilling activity going on with these shales as yet. Well, hopefully there will be one day, but not at this time. So we have shales all over the United States, as you can see, all over the 48, as you can see. And that has created a surge of activity in drilling and production in these shale types.

Here we have the production history of the shales. As you can see, in the early life of shale production, this is the recent shale production, you can see in the early years the red, which is from shale located in Michigan, dominated shale production. But as we move into the 2000s and we go up into 2008, you can see the blue, which is the Mid-Continent, primarily the Barnett shale have begun to dominate the production of the shales. I believe -- not I believe -- I know, it is documented, that 75 percent of the shale production to date comes from the Barnett. And you can see the growth, the growth is tremendous. Now, the Natural Gas Supply Association believes that shale, one day, I think they say the time is 2010, would provide about 25 percent of the production in the lower 48. Will that be the case? We do not know as yet, but the potential is enormous, and the possibility of it happening is certainly there.

What about in Canada? Well, the shale development in Canada is not as far along as we have here in the lower 48, but activity is ongoing. There are several shales in Canada. We have the Horton Bluff, the Utica, and the Lorraine Shale in Eastern Canada, we have the Muskwa, a shale in the Horn River Basin in British Columbia, we have the Montney shale in the Western Canadian Sedimentary Basin. The Western Sedimentary Basin is, of course, that basin that provides a lot of production here from the North, here into California.

Now, in East Canada, the producers have tested the Utica Shale and that shale produced -- the one well, the discovery well, produced 1,000 Mcf per day. In the Western Sedimentary Basin, three wells were drilled into the Montney shale, and we had results of 8,800 Mcf per day, 6,100 Mcf per day, and 5,300 Mcf per day, quite encouraging. And I believe there are other shales in Canada, I just have not listed all of them here, but there are other shales where activity is ongoing. So there is a lot of potential also north of the border in the shales.

Now, Recoverable Reserve Potential. Now, this is certainly an uncertainty, and it is listed as an uncertainty here because, really and truly, we do not know. And the only way we are going to know how much we are going to recover is through more drilling. Now there are estimates of the Original Gas-In-Place -- when I say the Original Gas-In-Place, I mean the total amount of gas in the ground that exceed 3,000 Tcf; now, you are talking about a lot of gas, okay? Think about that -- 3,000 Tcf. Where the uncertainty lies, and there is no doubt about the amount of gas down there, in general terms, where the uncertainty lies is how much of that we will be able to recover. And there is a broad estimate, a broad range of estimates of how much is recoverable. There are estimates on the low side, about 267 Tcf, and estimates on the high side that says about 842 Tcf; either way, it is a tremendous amount of gas we are talking about. Now, the major differences in these estimates come from really two shales, the Marcellus shale, which I showed you, is the big shale up in the East, and the Haynesville shale, which is the one that is between Texas and Louisiana. But what I have here on this table here is a composite of the best and most recent estimate of recoverable reserve potential. The total comes about 800 Tcf, but it is in the note here, that there is no certainty of this number.

Now, even if that number is wrong by half, you are still talking about 400 Tcf, you are still talking about quite a lot of gas, a lot of it. Okay.

This schematic here tries to represent the uncertainty in the economic environment of the shales. And what I have here established is a relationship between prices and the horizontal rig count, not a total rig count, just the horizontal rig count. And as you can see, prices and rig count rise and fall almost together; as a matter of fact, in recent times, the prices have collapsed -- well, I should not use the word "collapse", have fallen quite a lot, and so has the rig count. Last year, the horizontal rig count was somewhere over 600; today, I believe it is just over 400. But prices have gone from 13.00 in the same time to about $4.50, today. Right? I think that is what it was yesterday, $4.50 or $4.40, or something like that. So the prices on the rig count do track each other. So this creates a degree of uncertainty in the industry in terms of how much development will be seen, how much new development, because this is what drilling does, is new development. That is what it brings up first. So that uncertainty certainly presents a little challenge to the industry.

The other uncertainty, of course, is the environmental impact, and we have to consider this whenever we are talking about development of oil and gas. One of our speakers is going to talk a lot more about this later on, but I will talk about it just a little bit today. The first one of the environmental impacts are the ones of concern which is the surface disturbance. And that surface disturbance can manifest itself in terms of erosion, in terms of the climate water quality, in terms of the disturbance of some of the natural habitat. All these create potential environmental impacts. Then, of course, we have the greenhouse gas emissions, the production of natural gas obviously creates the production of carbon dioxide, or greenhouse gas, and also methane, which also has the potential of greenhouse effects.

The third one is the potential leakage into the groundwater. Well, of course, I just told you about the hydraulic fracturing, and in hydraulic fracturing really you have treated water, and water is treated with some chemical that has been pumped into the subsurface of the ground. Now, if that treated water, and it is treated with some sort of chemical, should leak into the groundwater, you could have a problem. Now, a lot of the development in the shales is occurring near major population centers. The Barnett shale which is the most developed of the sales is occurring near Fort Worth, Texas. So this is really a potentially risk. In addition, the hydraulic fracturing also creates another problem that is subsidiary to this one in the sense that there is a tremendous amount of water that is being used to fracture these wells. So there is a huge amount of water that is being pumped into the ground, even though most of it is retrieved, some of it is not, so some of that water remains in the subsurface. Once that water is retrieved, it must be disposed of because, remember it is treated water, it must be disposed of. So the disposal of that water presents a potential environmental problem. So these are all things that must be concerned about. Now many of the restrictions, many states like New York, Pennsylvania, Texas, have put regulations and rules and procedures in place to try to take care of some of these problems, but still the concern is there, and one of our speakers will address this a little more later on in the day.

So what are the issues that are outstanding? Of course, there is a lot of uncertainty involved in the development of shales. And there are several issues that must be discussed, one, will the future production of natural gas from shale formations meet the expectations? Right? Now everybody is excited about the shales, we all are, well, I am, I do not know if you are, but I am. But will it meet our expectations? That is the question. The other thing that we must be concerned about is the factors affecting the reliability of recoverable reserve potentials. I mean, we have a wide range of estimates right now, 267 to 842. Okay? What are the factors involved here? How reliable are those things? The next issue, the pricing environment. How will that affect our drilling programs? The potential environmental impacts, which we just talked about here for a little while. The biggest issue, which will be discussed by one of the people that you will be hearing here shortly, obviously, is will the shale production displace the need for LNG, or LNG importation? Will shales continue to gain market share in the lower 48? And will shale formation continue to be a reliable long-term source of natural gas?

So there are several issues that lead to the discussion, and the staff here at the Commission is looking for some of your input in trying to decide some of these issues. With that, I will end my presentation, even though there is a lot more stuff that I can talk about. But Ruben told me I better not talk too much, otherwise he is going to put me out. But anyway, I will end my presentation here and open it up for any questions or comments anyone may have. Thank you for listening.

COMMISSIONER BOYD: Ruben, I do not have any questions, thank you -- I mean, Leon. Does anybody -- I should have said this at the beginning, this is a workshop, this is not a formal hearing, so try to make this as informal as possible, so if you have got a question, come to the mike at any time. As indicated, identify yourself, and then have at Leon.

MR. KUSTIC - I am Tim Kustic. I am with the State Division of Oil, Gas and Geothermal Resources. I just had a question about your last slide with the list of questions where you had -- you were talking about the pricing factors and I was curious, did you look at all about the cost of drilling a well in shale vs. traditional sandstone, limestone? I mean, how does the cost of drilling and completing a well compare with the more traditional sandstone, limestone? And, I mean, is there a longer return with that? I was curious if you looked at that at all.

MR. BRATHWAITE: Yes, to some extent. Well, obviously this is a short presentation of my paper and I could not get in every issue that is in the paper. If you look in the paper, there is some information about the course of drilling horizontal well as compared to vertical well. And one of the things that the people explained is that there are two factors that really determine the course of drilling the horizontal well, the vertical depth and the horizontal extensions, and those are the two main factors that determine the cost of drilling and completing. And the paper also developed three curves, depending on the the horizontal extension, that shows the cost. It is actually on page -- I do not remember exactly what page it is on in the paper, but it is there in the paper. So, yes, we did look at that. Questions, comments? If not -- oh, I see somebody in the back. No? All right, well, thank you very much for listening.

MR. BOYD: Thank you, Leon. I am holding my questions for later.

MR. BRATHWAITE: Okay.

MR. TAVARES: Next we have Robert Kennedy. He is also part of the staff here at the Commission. He is going to present the LND Uncertainties Paper. Robert.

MR. KENNEDY: Thank you, Ruben. Hello, Commissioner, Susan, everyone, thanks for coming. My name is Robert Kennedy and I will be talking about LNG and certain key issues today. As we just learned from Leon, there has been a lot of changes in the --

COMMISSIONER BOYD: Speak up, Leon.

MR. KENNEDY: Oh, in the domestic production of --

COMMISSIONER BOYD: I mean Robert. I am not here today. I am slow today. I just got back from Alaska late last night. I have not awakened yet. I know more about gas than I ever thought I would know, as a result.

MR. KENNEDY: As I was saying, there has been a lot of changes in the domestic production of natural gas in the United States, as Leon has pointed out. And, no doubt, that has had an impact on the LNG market. And this comes at a time when things are constantly changing and evolving in the international LNG market. So without further ado, let us get started.

The first thing I would like to do very quickly is provide a framework for my presentation. The first thing I will do is provide an introduction as to what LNG is, what the properties are, how it is made, how it is exported and imported, a little bit about the markets. Next, I will talk about the highlights, which I think Ruben did a good job of that kind of describing some recent events with LNG in the United States market and also around the world, I will talk about that a little bit, as well. And then I will take a look at specifically California and some of the background California has had with LNG. And then I will take a deeper look at LNG around the world, identifying some of the markets for LNG and how these markets work and interrelate with each other. And then I will take a forward look at LNG and some of the issues we should consider when looking at LNG for the future, and then finally I will wrap things up with some discussion questions for the panel to consider.

Okay, so what is LNG? Well, the letters stand for Liquefied Natural Gas and, as we learned in our science classes, matter has three stages, solid, liquid, and vapor, and you can convert to one another by changing temperature.

Well, that is how LNG works. When you super cool the natural gas into vapor form to -260 degrees F, you get a liquid form which is 600 times the size of natural gas. So now you have a liquid form of energy that is very energy intensive, which makes it more conducive to be transported over waters, in very large tankers that have cryogenic storage tankers. And the LNG is produced at what is called Liquefaction Export Facilities and they arrive at what is called Regasification Import Facilities, where it is converted back into natural gas and fed into this local natural gas pipeline system. Just to highlight some of the markets up there, we have the Atlantic Basin with some exporting countries such as Algeria, Nigeria, Qatar, Trinidad, and Topago, which export to countries in Europe, Eastern U.S. and the Gulf of U.S. For the Pacific Basin, we have Australia, Indonesia, East Russia and Alaska, which exports to India, China, Japan and Korea.

Now I want to talk a little about the history of LNG in the United States and we have already touched upon this, so I will not spend too much time on this, but as you can see, we have been importing since 2005 and leading up to 2007, there has been upward trends of LNG import. And we maxed out in 2007 when we were averaging about 3.25 Bcf per day, and then, as you can see, there was a big drop-off in LNG import. Right around this time, inventory levels in Europe was maxed out and the United States was paying a much higher price for LNG, domestic production was on the decline. Conditions changed when we got over here, the price paid for LNG flip-flopped, the U.K. was paying a much higher price for LNG than the United States, as well as Japan, which is the biggest importer of LNG. Around this time, as we can remember, there was a big run-up in energy prices, but during that time other markets around the world maintained superiority as far as how much it was going to pay for LNG, and also, we saw domestic production increase during this period, so we saw a trend of a 1 Bcf per day import to the United States, and that trend has continued up until today.

Okay, I am going to be referring to this slide a few times in my presentation. This shows some of the landing points for LNG around the world, and some of the receiving prices, and this is as of March. And I just want to remind everyone, as far back as a year ago, prices in the United States was about $13.00 per Mmbtu, which is very much higher than what it is right now, but prices in the U.K. was about $15.00, and the price in the Asian market was about $20.00, so LNG was going to all the markets that was paying a premium price for supplies. And as you can say, the gap between what is being offered in the European market and also the United States market, the gap has shrunk dramatically. So conditions are starting to form such that LNG could start to come to the United States.

Okay, now I just want to take a little trip down Memory Lane for California with regards to LNG. As soon as a couple years ago, 2007, there were five projects on the table, and now there are about two, and the law has changed since then. For the Port of Long Beach, this was a project proposed onshore in Southern California, and the city decided not to move forward and review this project, citing that it was unsafe to local residents, and this decision was upheld in court, and the Applicant has since rescinded its application. Next, we have Cabrillo Port, which was an LNG import facility proposed off the Coast of Malibu. This project actually went through the whole state and federal review process and it was found to not meet California's stringent environmental law, and thus was defeated. Next, we have OceanWay, and this project was rescinded at the beginning of this year, and in a letter from the Applicant, they cited market conditions as the reason why they rescinded their application, and I will talk a little bit more about that. So right now, two projects remain, which is ClearWater and Esperanza. ClearWater has submitted an application, however, for about two years now, things have been moving slowly and there has not been any significant progress in its application process, and there has been no indication as to when things will get moving again. And for Experanza, they have yet to submit an application, and no word has been given as to when they will submit an application.

So I just want to paint a picture, when all these projects were coming down the pipeline, things were much different back then. Domestic production was on the decline and there was a decreasing imports from Canada, and also there was a rise, a trending rise in LNG imports to the United States. If you fast forward a couple years to 2008, and you see that demand from 2008 to 2007 was flat, and there was an increase in domestic production, and now, all of a sudden, according to experts, we have this vast amount of new natural gas reserves in the form of shale. These new market conditions have kind of forced these applicants to take a good hard look at the market and question whether or not they should proceed.

Okay, now I want to talk a little bit about some of the markets around the world, first starting with the Asian

Market, which is the number one consumer of LNG, for example, Japan, India and Korea combine to consume about 70 percent of the LNG in 2007. These countries have minimal domestic natural gas production and little above-ground storage capacity, so they rely a lot on LNG in the above-ground storage tanks. And the way they consume LNG is on a seasonal basis, based on weather. So these import facilities have a low utilization rate. And the way they use energy can be switched with crude oil, so that is why when LNG lands in these countries they tend to be priced against the price of crude oil. The same is true for countries in the European market, they do switching with crude oil, so LNG is linked to the price of crude oil. The European market is the second largest consumer of LNG in the world, and they are supplied from Africa and Qatar (phonetic). A lot of LNG goes into Spain, but if you move into Eastern Europe, they get more of their gas from Russia, which is piped through the Ukraine. And as some of you may know, earlier this year, there was a dispute where Russia cut off supplies to Eastern Europe. So this has caused a lot of European countries to take a hard look at LNG, to think about diversifying their natural gas portfolio. And their infrastructure is lacking and not very integrated, especially when compared to the United States.

Now moving on to the North American market, the difference between this market and other markets is that we do have a significant amount of domestic natural gas production. Compared to other markets, we are not a big importer of LNG. Supplies typically come from Trinidad and Tobago, and North Africa. Now, unlike the other markets, when LNG comes to the United States, it is a price taker, which means it is priced against domestic natural gas price. And the North American Market is seen as kind of a swing market. As I have said, in Asia and Europe, they consume LNG on a seasonal basis, based on weather, so when their consumption is down, the North American market is seen as a stomping grounds for LNG because they have more extensive infrastructure and it is very flexible.

This next graphic is, I believe, one of the most important graphics in my presentation, and I want to thank the consultant from RW Beck for supplying this graph. First, I want to explain what we are looking at. The blue line right here is the difference between U.K. price for LNG, and also the U.S. price, so whenever that difference is negative, in other words, when the U.S. is paying more for LNG than the U.K., this blue line will dip below the mid-point line where the negative dollars reside; conversely, when U.K., is paying more than the United States, the blue line will go above the mid-point line right here. The gray bars right here, this shows import to the United States for LNG. So if you look at the trend here, when the blue line is above the mid-point line, in other words, when the U.K. is paying more than the U.S., you see that there is relatively less amount of LNG being imported to the United States. Conversely, if you see right here, the United States is paying a much higher price for LNG than the U.K. Correspondingly, you see there is a big increase in LNG through the United States.

I just want to make one last point on this topic. As Ruben mentioned, we did have a conference call with FERC yesterday, and these numbers have been updated for me. Landing prices for LNG in Europe was about $3.50 over here, $3.20 for Spain, Belgium was importing at $3.35. Looking at the United States, the landing price was $3.59. And, correspondingly, FERC was able to produce a graph that shows that there was an increase in LNG imports to the United States. So the point I am trying to drive home here is that the market is very price driven.

Okay, looking ahead for LNG, I just want to offer some food for thought here. The outlook for California, there will be more sources of natural gas available and Bill, I am sure, will be able to touch more upon this in his presentation. There is a ruby pipeline natural gas pipeline that will bring more supplies out of the Rockies. There is a LNG facility in Baja, Mexico that has the potential to supply more natural gas to Southern California. And also, there is an approved facility up in Oregon, Bradwood Landing, that has the potential to displace more natural gas, thus freeing up supplies for California. LNG also has a natural gas quality issue and I believe we have a presentation from the South Coast Air Quality Management District that will talk more about this, but typically when LNG is imported from foreign countries, they tend to leave in the hydrocarbon liquids, which, when burned, the power generation tends to emit nitrogen oxide, which is an emission problem. So there has been a lot of discussion about this with regards to LNG.

Moving forward to the carbon footprint of LNG, this is still a new area of study and from everything that I have seen, there seems to be a consensus that LNG does have a smaller carbon footprint than coal, although the distance that the LNG tankers have to travel, that does provide an X factor right there, and also when looking at carbon sequestration, that could also change the picture a little bit. When comparing the carbon footprint of LNG to natural gas, there seems to be a lot of disagreement in that area. One of the things to say about LNG is, from foreign countries, when it is extracted, there is a large volume of natural gas that comes from these fills when they produce the LNG, so on a per energy basis, it is less carbon intensive for that reason.

Looking at geopolitics, we have to keep a close eye on what is going on between Russia and Ukraine. If there continues to be dispute there, that will provide more incentive for Europe to really explore the potential for LNG. And also, there has been talk that Russia may be working with other natural gas exporting countries to form an energy cartel somewhere to OPEC.

Looking forward to the future, there will be new Liquefactioning and Regasification capacity in the next six years. The gasification capacity could double, and I say "could" because, given the current worldwide recession going on with the credit problems, that could cause problems with these projects coming on line. Even when they do, demand around the world is really low right now. The big attention being given to the liquefaction capacity already right now in East Russia and Indonesia, more liquefaction is coming on line right now. And a lot of experts are trying to think, "Okay, where is this extra LNG supply going to go? Demand around the world is low." So they look upon the United States as the landing place for this additional supply because we do have the storage capacity to take on this additional LNG supply. And this is a highlight in this graph right here, I just wanted to show this because looking into the future, there is conflicting views as to whether significant amounts of LNG will arrive to the United States or not. According to Water Board and LNG, they are very optimistic about the future of LNG. They are projecting imports going all the way up to 5 Bcf per day. But EIA takes a more modest outlook. While there is a temporary increase, it tends to taper off. Again, only time will tell. So I just want to leave everyone with these discussion questions for consideration for our panel. Factors to determine landed LNG prices in the U.S., Europe and Asia. One thing I want to put out there is energy commodity trading does drive prices, and perhaps we can talk about what kind of effect that will have with LNG. Let's talk a little about the link between crude oil prices and LNG, especially in Europe and Asia. And also, if we could also talk about looking forward -- will we see demand around the world if there is an economic recovery? Next, LNG availability given price differences between the U.S., European, and Asian markets. We have already seen a flip-flop of prices for the U.S. and Europe. Perhaps we can talk about will there be a flip-flop with the Asian markets and U.S. Will U.S. surpass the price being offered in Asian markets right now? And I think it is very important that we talk about the potential for an energy cartel for natural gas. If a cartel is formed, what kind of impact will that have? As we see that, similar to crude oil, OPEC does play a large role in driving the price of crude oil; what is the potential for that to happen in LNG? And finally, I want to talk about carbon footprint, if there is any consensus out there about the carbon footprint for LNG with regard to coal, and if we can talk further about conventional natural gas and also unconventional natural gas. And the last question, I kind of leave it open for discussion, or whatever, if anyone would like to put forward non-economic factors to drive development of LNG. I thought one thing we could talk about is application process for California, some of the environmental regulations that we see in CEQA, and also federal standards in NEPA, some of the state's emission mitigations. Well, that concludes my presentation. If there are any questions, I will be happy to answer.

MR. TAVARES: Thank you, Robert.

COMMISSIONER BOYD: I have one question, I am not sure it is fair to ask it of you or to ask it of all you and the two preceding speakers. As I was looking through the Agenda today for an appropriate spot for the question, I just started to throw it out here and maybe it will get answered later, if not now, or by Leon, or Ruben, as well. And it is the subject of gas to liquids, and what impact the interest in gas to liquids, what might be the potential future of gas to liquids worldwide and how it affects gas being available -- just compressed natural gas being available on the world market, or even LNG being available on the world market. I know a lot, as you indicated, a lot of LNG finds its way into Asia and to Europe, Europe in particular. Europe has also dieselized substantially for its transportation fuel, and gas to liquids looks kind of interesting to those folks. And a lot of facilities are going up in the Middle East that are particular, I guess, to produce gas to liquid. We have looked at it here for years, but it has never seemed to be economic. I just wondered if there is enough interest in that subject such that there is enough demand even to be felt at all by discussions about LNG or just natural gas availability worldwide? Simple question.

MR. KENNEDY: One thing I can say, as I mentioned about Regasification capacity to come on line, and I think it is only a matter of time before we begin to see price competition to occur around the world. I see LNG market going away on a global scale, where liquefaction capacity is coming on line. What is occurring with the shale is not confined just to the United States and Canada, it has the potential to occur around the world. And so the markets are becoming more and more integrated as we move forward. I cannot give a definite answer to that.

COMMISSIONER BOYD: Maybe someone can throughout the course of the day or anybody who is a little closer to this might be able to throw out an opinion. We will not keep it pending now for you, or those who appreciate you, but maybe at some time today, somebody will have some views on that. Thanks.

MR. KENNEDY: Does anyone have questions? Yes, sir.

MR. TAVARES: Come to the microphone, please.

MR. COX: Hello, my name is Rory Cox and I am here from Pacific Environment. And you mentioned that there was disagreement in this study, the carbon studies that were done on LNG. Can you talk about those studies and where the disagreement is -- which studies you looked at?

MR. KENNEDY: If you referred to my paper, they are listed there. And I just want to point out the disagreement. There is some opinion out there that, when looking at LNG compared to natural gas, it has a smaller carbon footprint. And as I have said, they are able to extract a whole lot more natural gas from these for liquefaction purposes, so on a per energy basis, it is less carbon intensive. But like I said, the X factor is the distance that the tankers have to travel. Other things to consider is carbon sequestration, that has not really been explored. And I think there has to be a clearer differentiation between the carbon footprint for a convention and unconventional natural gas.

MR. COX: Which study actually details the -- you said the natural gas is close to the liquefaction facility?

MR. KENNEDY: Right.

MR. COX: Which study details that?

MR. KENNEDY: That was in my paper study. I can --

MR. COX: Who funded the pay study?

MR. KENNEDY: Excuse me?

MR. COX: Who funded the pay study?

MR. KENNEDY: It is Tempra.

MR. COX: Okay, thanks.

MR. TAVERES: Leon has a question for a fellow staff member.

MR. BRATHWAITE: Leon will have his time later on.

MR. TAVERES: Okay, Commissioners. Next, we have Bill Wood. He is our veteran member of the staff, of the Energy Commission. He tried to retire, but we encouraged him to come back. So he is coming back and he is going to give us a presentation on the natural gas infrastructure. So, Bill.

MR. WOOD: Good morning, Commissioner, and Susan. I have always wanted to say this, "Good morning, gassers and gassettes."

COMMISSIONER BOYD: Good thing you retired.

MR. WOOD: Well, I am not really certain, you know, my goal has been to just work about 40 hours a month, and the last two months it has been closer to 100 hours a month trying to get this report turned around. And in some instances, as I was preparing it, my grandkids were running through, and so sometimes I might have missed something in my preparation. Before I get started, with regard to your question with regards to gas to liquids, I have thought about this a lot over my period of being here at the Commission and I think back that, many years ago in New Zealand, I had natural gas resources available to it, and it elected to go forward and convert those to liquids, rather than importing petroleum products to serve as their fuel for vehicles. I know that, at least in one instance, I have had a country come in, if I remember right, it was Borneo or something over in that general area, that had stranded a lot of natural gas available to it, and they were interested in natural gas to LNG, and I suggested to them that, really, if they were to convert the gas to liquids, either gasoline or clean diesel, that they would always have a market here in California because we are always looking for that kind of fuel, and that would be a sure market and not necessarily --LNG may not be such a sure market for them. That was my thoughts at the time and I think I still kind of go along with that particular idea, that there is a place in the market, and I think in some instances they would probably would have more fluid market if it was converted to LNG -- I mean converted to liquids. Liquid does not seem to have that same glorious, or sexy, or whatever terminology you want to think about, and is probably a little more energy intensive, but so much for that. I hope that sheds a little bit of light on things.

I am here to talk about the infrastructure and how it is impacting California. You know, I like talking about infrastructure because it gives me the opportunity to look at the big picture; I do not like looking at little tiny things. So when I look at infrastructure, I have to look at both the pipelines inside and outside the state, I have to look at production, we have to view storage and how that impacts supply, we have to look at demand in different locations, and do we look at normal demand, or do we try to look at something that is a little extreme in demand to see how the system can be tested? So we are basically doing supply and demand balances. And then, more recently, now we have got this new thing that has been thrown into the system, it is called Renewable Resources. These are new, we are not really certain how they are going to impact the operation of our natural gas system, I am going to touch on a couple of issues with regard to that, but indicate that we have a workshop coming in, in June, that hopefully will provide more light on this than I can here.

Then associated with this, then, there are a number of new projects sitting out there with regards to pipelines, as well as storage, and we will talk about those and then, of course, we have always got a summary, and then we have added onto this, so a series of issues which hopefully I will cover during the presentation and I will not have to depend on those two to defend me.

With regards to pipelines, pipelines serve customers both in California and outside of California. And pipelines do not actually own the natural gas they carry, but they are purveyors, they contract out capacity, deliver and pick up gas at one location, and deliver it to another location. And that has an impact, then, on the deliverability of gas, say, to California. We may have a pipeline that has the same capacity from one end to the other, and the pipeline connects to one of our utilities and has exactly the same capacity, but yet that capacity may not be fully utilized because of upstream requirements. Now, trying to determine what the deliverability, or what you can expect to find at a given location, is very market-driven because the shipper on the pipeline has several options that are available to him; he can deliver to California, he can deliver to his upstream customers, he may have responsibility to deliver gas to California, but his upstream customers need more gas, and so he may drop off his gas in the north, or the south, or outside the state, and maybe he will have storage in California that he can make it up with, or maybe he will have capacity on another pipeline that he can bring in gas to fill up -- to make that need. So all of these things, then, have a tendency, then, that make it difficult to determine what the actual capacity is to receive, or how much capacity he can rely on to receive gas at any given point.

Another thing that I have highlighted here is that utilities have multiple receiving points. If we were to look at PG&E's line 300 or the Baja path, there are capacity receiving points all the way along that pipe that exceed the facility for PG&E to receive gas. If we were to look at Topock Needles, I like to pull them together because they are so close, PG&E has a number of receiving options available, both from El Paso and from Trans Western, as does Southern California Gas Company, and also we have Southern Trails that also delivers into that area. So the combination of how much gas can be relied upon to receive at the California border due to upstream commitments, or the receiving capacity actually within the State, one of those two will limit the amount of supply that we can receive in California.

We are going to spend a lot of time on this particular figure, it is a little small, but I think you can basically see what we have going here, it is the Western states and it shows all the pipelines that are coming into the state. And let us start off with Malin. Here is Malin --

COMMISSIONER BOYD: You know, Bill, "little small" is an understatement here, I will tell you. Proceed.

MR. WOOD: You need to get your bifocals fixed.

COMMISSIONER BOYD: They are fairly new and still…

MR. WOOD: Well, I wanted to get this all on one page, so you guys are going to have to suffer. I can see it just fine. All right, we are going to start with Malin. Here we have GTNS, a capacity to deliver 2,100 MMcfd and PG&E several years ago was using something like 1,850 MMcfd as their planning number. I am not really certain whether that is still a good number or not. We have from Malin, we have Tuscarora, which has been put in, that can carry up to 125 MMcfd, that will pull gas away before it gets to Malin. We have right above Malin, Klamath Falls, it is a growing neighborhood. It has a new power plant there that is pulling more gas out of GTN (phonetic). And then I reviewed and saw that the overall demand for Oregon and Washington is increasing at about 3 percent a year, so that is also then drawing away capacity that could be serving California. So it may very well be that, when I say "reliable", or the peak capacity we could rely on, or in this case a limited capacity we could rely on for Malin, Malin is 1,850 MMcfd, it may be less than that. I can remember some cold cold weather where this dropped down to 1,500 MMcfd. So we are working with 1,800 here at this point.

Now we are going to Kern River. Kern River brings gas down from Opal, which is right there, and brings it all the way down into Daggett, and then it gets by -- well, anyway, there are two pipes that go this way and this way, in the lower San Joaquin Valley. The current capacity on Kern River is 1,750 MMcfd, but if you were to look inside of California, you would see that there is a receiving capacity of more like 2,600 MMcfd, that includes the non-core customers who are receiving about 1,000 MMcfd, as well as in this general -- where all of this business is in here, there are inter-ties with PG&E, SoCal, and there are also some deliveries into non-utility customer classes. So what is happening here is that, though they have 1,750 MMcfd in delivery capacity, California is only receiving about 1,500 MMcfd. The rest of it is being dropped off up here, principally in the Vegas area, as well as to serve some power plants along the way, and then some other drops here in Utah.

Now we have Topock. I have included with Topock Needles, and if you were to add up all the delivery capacity there between El Paso, Trans Western, and Southern Trails, it would come up in the area of 3,000 to 3,350 MMcfd. Utilities, on the other hand, have the capability to receive about 2,600 MMcfd at that location. It is interesting that this provides this unbalance of delivery capacity vs. receiving capacity, it gives the utilities the option, then, to play off different supply sources and then help reduce the gas prices within California. But I am indicating that we only can rely on 2,450 MMcfd at capacity here. The first thing that is happening is that -- and I may have to correct myself in this area later on, but at this point, my understanding is that Transwestern has the delivery capacity of 1,100 MMcfd, but they have just recently completed a lateral that goes into Phoenix, that has the capacity to deliver 500 MMcfd. Now whether that is fully subscribed or not is irrelevant, as far as I am concerned, because there is that capacity to deliver 500 MMcfd in the Phoenix area. That basically, then -- oh, and the other point is that, as far as my understanding is, there was no main line additions made, so therefore that basically strands between Phoenix and California border about 500 MMcfd of capacity, so therefore we have lost 500

MMcfd of capacity if all of the deliveries are made into Phoenix. The second thing is Mojave. See that little red line that just popped in right there -- watch closely -- there it is, that is the Mojave pipeline. Historically since it was built, it has the capacity of 400 MMcfd, and since 1992 up to the most recent last couple of years, that slowed about half of its capacity, or about 200 MMcfd. And that was delivering into the enhanced oil recovery operations in the lower San Joaquin Valley. But lo and behold, El Paso converted -- can you see that red line, it is this one right here -- I am sorry, I should have made them bigger -- El Paso converted a portion of all the American pipeline which they purchased several years ago, they call it "Line 1903." That particular pipeline hooks up with Mojave at this point and, through an ingenious methodology in terms of enticing customers and shippers, Mojave is now flowing nearly full, and it is taking all of that gas down to Ehrenberg Blythe area. So basically under those circumstances, Mojave's delivery point has shifted from Daggett to Ehrenberg, and not only is Line 1903 taking the 300 or 400 cfd that El Paso is putting onto it, and also Trans Western puts some onto it also, it is also picking up about 50-100 MMcfd of Kern River gas. Kern River gas last year delivered 1,600 MMcfd, but 100 of it or so went south to Ehrenberg. So I have basically, then, downgraded the receiving capability of Topock by another 400 MMcfd, which gets us to the 2,400. Ehrenberg -- Ehrenberg is where El Paso delivers gas into California. I have indicated here a capacity of around 2,100 MMcfd, that includes 1,200 that they built to deliver into the SoCal system when SoCal has that receiving capacity, but it also includes an additional -- I have included now an additional 500 MMcfd for the All American pipeline, which they have converted east of California, burned to carry gas, as well as the additional 400 MMcfd that Mojave is now delivering to the Ehrenberg area. Now, it is interesting that SoCal can rely upon, then, receiving 1,210 MMcfd at that point; there is also some additional non-firm capacity that they could potentially utilize, but at this particular point here at Blythe-Ehrenberg, the gas can go a lot of different ways once it gets here. Partially, it can go south, and then on the Baja north pipeline, into Mexico. And it can either flow, or by displacement come back and serve all these big -- what is it -- around 10,000 megawatts of natural gas generation in this particular area. There was another point I wanted to make, but it is not there now.

All right, California production is about 800 MMcfd if you add in SoCalGas's capacity on top of the 120 MMcfd that PG&E receives. You actually get 1,000 MMcfd of receiving capacity, but California is only producing, oh, between 850 and we are forecasting a major drop-down to 700 MMcfd, so I just rounded things off to around 800 MMcfd. And it should be pointed out that more than half of that goes to non-utility services. It goes into -- is being produced and is delivered in this general area for enhanced or recovery operations and co-generation. And I think I mentioned up here that Kern River delivers about a million cubic feet per day for non-utility utilizations. PG&E and SoCal get about 500 MMcfd.

That gives us, then, the delivery capacity of around ten billion cubic feet per day. We have receipt capacity of 900 or nine billion cubic feet, but I think, as we have gone through this, we can only under abnormal conditions, I think we can only rely on 7,800 MMcfd. Now, while I am on this particular slide, since I do not reproduce this later, I want to talk a little bit about some of the new projects. We have Kern River, who is planning on putting in about 175 MMcfd of new capacity. Basically, what they are doing is they are -- I like to call it -- they are "ballooning" this particular portion of their system. They are going to do it -- I have not looked to see specifically -- but it is probably going to be adding additional compression, which will allow them to move more gas to California. Up here in Malin, we have two pipelines are being proposed to bring gas from the Rockies to the area just north of the California border, one of them is Ruby Pipeline, and the other was, I think, Sunstone. I think Ruby is a little further ahead than Sunstone, but in any event, there is the potential of at least one of those pipes being built, and that would bring in a billion cubic feet per day, plus or minus. Over here in Koos Bay, there is an LNG facility being proposed and up here on the Klamath River, there are several that are being proposed. The interesting thing is, they do not add anything to PG&E's receiving capacity at this point. They add supply. And they would potentially be able to raise the supply receiving from 1,800 to say in the area of 2 bcf. But they would do nothing to add new supply into California. And it is interesting that, if one of these pipelines were to be built, and one of these LNG facilities were to be built, maybe in 10 or 15 years, you know, the demand may be sufficient to take care of all that. You know, that is one of the issues that we highlighted in here -- can the market really support one LNG and one new pipeline facility from the Rockies? In my estimation, at least in the short-term, there would be a lot of supply competition there if the LNG actually flowed to the facility. And then the question would be, would it be backing out Canadian gas, which is coming in from Kingsgate, or from British Columbia at Everett? Or would it be backing out Rocky Mountain gas that is coming in a northwest pipeline up to Stansfield? Or would the Canadian gas be dropping off, and this would just help backfill into that? It would be an interesting situation, the pricing mechanisms that would occur because of that would be interesting to follow, but at this point, it is an issue, we are not really certain what is going to happen in that regard. One other thing, no, we will not cover that now, we will do it later.

All right, now, we are going to look at storage. You know, storage is generally looked at with regards to meeting a short-term peak demand. For instance, in December, PG&E had an all-time peak demand that I never dreamed they would ever hit, it was like 4.7 bcf per day. Normally, their peaks are in the area of 3.5, 3.6 bcf per day. They pulled a lot of gas from storage. I cannot remember all of it, but I think they pulled close to 1,500 million -- I think it was 1,200 million out of storage, and the two independents pulled out about a billion cubic feet out of storage to meet that peak date demand. And either the day prior, or the day after, SoCalGas had an almost all peak day demand, they hit 5 bcf a day. They have done that twice in the last 10 years, the first time -- actually, they have done it three times, sometime in the distance past, and I do not know exactly when that was, but they also did it and, during the energy crisis, they hit 5 bcf a day, and then they did it again this last December. And natural gas storage is what helped them carry through those particular peaks. I think SoCal pulled out about 2,600 MMcfd to meet a short-term peak demand. In other words, that is a demand that lasts for a day or two, and then on the shoulders there will be some high demand, and then it goes back to what is a normal demand for winter conditions.

Now, I am also talking about what is a long-term high winter demand. Here, I am looking at something that is similar to what happened there in the energy crisis; we had a high demand that lasted from November through March, very very high during that whole period of time. It basically stressed the system. So I wanted to see what would happen if we were to do that again, so basically what I have done here is I have assumed that storage was full at the beginning of the winter season, that during the off peak periods of the day, during a five-month period, natural gas was injected into storage at maximum rates, and then was withdrawn during the peak portions of the day such that the working gas would be completely used up by the end of the last day of the fifth month. Okay, so looking at natural gas storage in this vein, PG&E has a peak day capacity of about 1,500 MMcfd, they cannot maintain that very long, and normally they are operating at considerably less than that. But if you were to look at their injection capacity, which is, if I remember right, about 300 or 400 MMcfd, and apply that, then, to their current storage capability, you would find over a five-month period that they could average withdrawal of about 400 MMcfd -- very very much reduced from their peak requirement because of the poor sandstones that they have, they are very -- they are not very permeable, and they do not give up their gas easily. SoCalGas, on the other hand, has indicated that they can maintain a 2,200 MMcfd withdrawal capacity throughout the heating season, but if you were to apply the long-term demand scenario, then they could actually only rely on average of about 1,100 MMcfd, but much better recycling capability. You will notice that the peak day to limited supply is very high at that ratio, same way with Lodi and Wild Goose, they also have very good working conditions. You know, and I was laying in bed last night thinking about this, I left out Kirby Hills. And I just do not remember how big Kirby Hills is, it is not huge, I do not think. But that should have been added here. But what it boils down to, on a peak day we could rely on about 4.6 bcf being withdrawn, but if we were looking at the long-term cold winter, probably a dry hydro year, we could get about 2.1 bcf out of storage.

All right, now if we put all this together, I call this Firm delivery, but it should be just "delivery", I think, rather than "firm delivery." But the state could receive in the area of 14 -- has the capacity of receiving around 14,700 MMcfd. The peak supply is only 12,000. Let's go across the top first, for pipelines we basically can receive about 9.3 billion from pipes under normal conditions, but under adverse conditions around 7 billion a day. Production is around 800, and then these are the numbers that we just talked about for storage. Peak supply is constrained by pipeline capacity, and if we are looking at a limited supply condition where "limited supply" means what is available on that long high demand winter condition, it is limited not only by pipeline, but also by storage. So we can look under very adverse conditions to receive about 9.9 bcf a day.

Here is a demand forecast. I have got five minutes? All right, we will go through this quick. Here is a demand forecast that was put together in the Cal Gas Report. This is historical peaks in the winter. You can see that we are up around 10 Bcfd here, it actually last year was around 10.6, continuing to grow. And this is annual average. This is forecasted from the Cal Gas Report with regards to an annual average. This is what they are forecasting the high demand day would be under cold and dry conditions. I was a little concerned about it being so flat, I could not sort of understand what was going on, so I just kind of extended this line further up here, just as kind of a what-if. I included on top of that, then, assuming that this represented a peak day, or short-term demand forecast, I put on top of it, then, what the peak supply would be available. We have an ample supply to meet the demand if it falls as the CGR indicates; if not, then some time in five to 10 years, we may have to add some additional combinations of storage and of pipeline capacity.

All right, now I have taken the same demand forecast and I have presumed at this point that it represents a long-term, cold weather demand, and then I have laid upon this, then, what the limited supply capacity would be. As you can see, the limited supply capacity lies right on top of the forecasted demand. This is similar conditions as occurred in the year 2000-2001 energy crisis. So if this configuration happens and this demand occurs, then we may have a year that is very similar to 2001-2002, that energy crisis, and during that time we spent over $19 billion for our gas supply, when previous years it was only around $8 billion. So under these conditions, new infrastructure is definitely needed. Renewable resources -- I will go through this quickly. CDR says we are going to drop about 1,400 MMcfd from a peak demand earlier of about 8 bcf in the summertime. Renewables add uncertainty to how the natural gas structure is going to operate. Renewables are not dispatchable, they do not really load follow very well. And they are not really available to meet peak day requirements, which means, then, there has got to be some sort of back-up or probably going to be natural gas. Options to supplement renewables on the electric side would be to build peaking units, or to continue to use combined cycle units. Peaking units are very expensive -- I should not say "expensive" -- they are very inefficient, they are about 60 percent more -- you use 60 percent more gas than a combined cycle unit. Gas utilities have a number of tools they can use. These basically are -- you have long-term weather forecasting, so if you work things right, you can plan your supply and your utilization of pipelines, as well as storage, to meet the requirements. But it may very well be that we may need more additional storage in some areas because of the cycle ability of the storage facilities, like PG&E takes all summer to fill their facility up, and they may not be able actually to meet a renewable requirement when a peak load hits.

This is Proposed Pipelines -- Pacific Northwest. If one or both, or either of those projects in the Pacific Northwest would go, we could increase our supply by 150 MMcf. If Kern River comes in, we can increase it by 145. Otay Mesa, which is basically LNG, I am going to spend a little time on this, and then we will just scoot through this, LNG at Otay Mesa has not yet received, as far as I know, a commercial load of LNG. So that leaves me with the understanding, thoughts about how reliable -- how much reliance can we put on LNG coming out of Costa Azul? If it does operate, and my understanding is that the first 300 MMcfd would go to serve power plants in Mexico, so anything over that, then, would be available for California, or other markets. Otay Mesa can receive 400 MMcfd into the San Diego service area, but it cannot go any further than that. There is no way that currently under current infrastructure conditions that that gas can make it into SoCalGas service area. So that means that anything additional, above that 400 MMcfd adds supply, but it does not add any additional capacity to the system. If one of -- I had not considered any of the other proposed off-coast LNG facilities mainly because I am wondering whether if one of them does get built whether it would be available during our next 10-year period. And this is a summary, then, of what happens with storage. Let's see, I had something on storage and then shale. One simple little thing on shale, El Paso has indicated that they have seen a 5 percent increase in their supply coming across their southern system, which indicates that gas out of the Permian is being backed out going east and it is now coming west. In my paper, I indicated in one of the figures a shift in pricing at the California border between Malin and between Topock, which I think is being driven by that. And then pipelines flowing east, they may or may not have a tax on California. You put more straws into the same supply region, more than likely it increases competition and prices could very well then go up, as we saw.

Summaries quickly. Pipelines -- we have to look at what the differences are between receiving and delivery capacities. Pipelines must be reviewed, I think, on a statewide basis because there are too many hook-ups inside the state to see who is going to get what share of each of the pipes that are being delivered. I think once the gas gets into the state, then there is enough capability for the utilities to move the gas around, to meet where they need it. Storage needs to be looked at on a short-term and long-term demand basis, not just the short-term. Winter, high demand, I do not know what I meant by that, I was busy with my grandkids at that moment when I wrote that one. Short-term, winter peak and prolonged winter peak provide different infrastructure requirements, so we need to think in terms of which one of these are we planning for, to meet the short-term peak, or should we be looking for the long high winter demand period, so that we do not suffer what we did during the energy crisis? Renewables add uncertainty to how the system is going to operate. New supply storage projects would definitely be a benefit. And in my mind, LNG's role in California is still very uncertain. And then, here are a number of issues that hopefully I have covered during the presentation. And I am overtime, sorry. I took 40 minutes instead of 25. Commissioner, questions?

COMMISSIONER BOYD: Thanks, Bill. No, I do not have any questions at the moment. Any questions out there?

MR. MEYERS: Hi, Bill. This is Richard Meyers of the California PUC. I wanted to understand your winter peak day trend that you produced a little bit more. Was it simply a trend of the historical peak days, of recent years?

MR. WOOD: Yes, since there is no forecasting there, it should not be any weight added to it as the forecasting, it was just basically taking the last five years and just kind of extending it out into the future kind of as a "what-if?"

MR. MEYERS: And so you did not look at numbers of meters, or heating degree days, or --

MR. WOOD: No.

MR. MEYERS: Okay, thank you.

MR. WOOD: No, it is just -- if you read in my paper, I talk a little bit about what could sustain that particular growth above what is in the CGR, but I do not want to get into it now, we are out of time. But we can talk about it, if you wish, on the side.

MR. MEYERS: Okay. And did you include -- it did not look like you included the expected Wild Goose expansion and the more recently further Wild Goose expansion?

MR. WOOD: Yes, those are in there. That last table that I went through rather quickly, under Proposed Facilities, I have in there Fresno, Lodi expansion, and the Sacramento storage facility. I do not know anything about a Wild Goose expansion that is going on at the moment.

MR. MEYERS: Yes, They just announced an expectation that they would further expand their facility.

MR. WOOD: Well, that one has not been included into it. When we finalize the report, I will make sure that kind of stuff gets there.

MR. MEYERS: Thanks.

MR. WOOD: Yes.

MR. PETERSEN: Thank you, Bill. Good morning, I am Don Peterson with Pacific Gas and Electric, and I do not want to belabor this, but I wanted to make a quick couple of observations. We will have more comments when we have our written comments later. Particularly for Ms. Brown and Commissioner Boyd, one of the concerns we have with Bill's approach is that, when he looks, for instance, at the Phoenix well off of Trans Western, that it does not take into account that it is really, we feel, a competitive market-driven situation in the Phoenix area. If Trans Western expands a lateral into that area, then it very well may displace El Paso Gas. But we think probably the most effective way to look at the impacts of a Phoenix lateral is to look at the overall supply-demand balance in the region. And I know you have the market builder model and other tools to do that, and we just think it will be very important in the final conclusions, when you are looking at the IPR, that you take into account the overall regional supply balance and demand balance because, at the end of the day, a lot of the shippers have choices as to where they can send the gas, and just because there is an additional amount of capacity that is desired to go into Phoenix does not necessarily mean that gas cannot -- or some gas out of the San Juan basin, or the Permian, cannot also flow to Topock. So it kind of, I am afraid, sends a message that it is more Draconian than we feel is really the case. So that is something we will follow-up on and we can talk to Bill off-line.

MR. WOOD: Thank you. Don.

MR. PETERSEN: Quickly, Bill, your Topock number is an old number, it is 2,021 in terms of the firm capacity, not the 1,835 that you have up there. So I will just tell you that right now.

MR. WOOD: Okay.

MR. PETERSEN: One of the points that I think is important is that we planned for an APD, and under an APD condition, we are serving all of the core load, and it is assumed that we are serving zero percent of the non-core load; that has been a longstanding policy. So when we look at serving load in California, just know what the utilities' obligation to plan really is. Now, that does not say we are going to be serving zero percent, in fact, the non-core enjoys a very high level of service, even under those worst case conditions. But it is important to just understand how the planning perspective from the utilities. That leads me to my last point, which is, Bill, when you look at those lines that Richard Meyers was just referring to, extrapolating the peak date trend, it is a little bit unfortunate, and Bill would not have necessarily known this, comparing apples to oranges, because one of the charts in the CGR is focusing on average day in a peak month, so when that line was flat, we were not comparing peak days to peak days, so it was not a true comparison, and we can talk some more with Bill afterwards because I know you will want to get that straight when you get to the end of the process.

MR. WOOD: Right.

MR. PETERSEN: Thank you.

COMMISSIONER BOYD: Thank you.

MR. WOOD: Thank you, Don. Anybody else? Thank you.

MR. PETERSEN: Thanks, Bill.

MR. TAVARES: Thank you, Bill. Next, we have two presentations on Shale Gas, the first is by Gordon Pickering. And Gordon works for Navigant. He is a Director and the fuels is in a lot of his practice. He has over 28 years in Natural Gas and Power Industry Consulting, both in the United States and in Canada. He has been involved in exploration and production of natural gas, and also Mr. Pickering authored just last year The North American Natural Gas Supply Assessment. This study was done for the American Clean Skies Foundation. So, Gordon? And you have 25 minutes.

MR. PICKERING: Good morning, everyone. My name is Gordon Pickering. Thank you, Ruben, for that introduction. If I speak into the mike, it will work better, I guess. I was consulting for eight years for Navigant Consulting. My longer background is in industry, both in the production and exploration side of the business, and in the marketing side. Today, I am going to talk about something that is very exciting to the industry, we feel. It is a new development, it has caught some folks -- especially some of the folks in the forecasting business -- at odds, and we are going to talk a little bit about that today. But mostly it is a review of the study that is almost a year old now, it is hard to believe. We announced the results of this study in July of 2008, to a press conference that was in Washington, D.C.; since that time, there has been a lot of follow-up with respect to the study, and I am going to talk a little bit about the main summary of that study, but also talk about some updates since then, in the last year or so. And finally, I am going to talk about some implications of the study going forward, and targeting to this audience here in California, also; it is not just an Eastern or Mid-Continent issue.

So this was a study that we were assigned by the American Clean Skies Foundation of Washington, D.C. This is a nonprofit foundation headquartered in D.C., like I mentioned. And the process was -- an extensive process -- was to basically gather resource data that was difficult to find. The resource base is something that is a difficult subject matter and also and also comes up in terms of study and thoughtful study periodically. And because of the rapid change in the resource base in North America, we found that there was not a lot of good material that was available to do our study with, so therefore we went to the horse's mouth, we went to 114 different producers, covering 90 percent of the North American production side of the business, a 60 percent response rate in our survey. We also reviewed in detail reports both in terms of public reports to the media, but also annual reports and other public reports that the producers were releasing to the public. And we also talked to production officials, all of the major shale producing states, we talked to for this study. And there are some basic summary findings that we came up with, again, in the July release of the study. I will also mention that a copy of this study is available on Navigant's website at the back of the presentation, I give you the website location, so if you want to look at and have not looked at the study, you are free to look at the entire study that it on our Navigant website.

Essentially, the results of the study have showed that gas production from domestic unconventional gas supply have ramped up sharply in the last several years. And this is a new development, and it is a rapid development, and it is something that has not really slowly been developing, so therefore it is hard to put your finger on. As a matter of fact, the growth of the industry is ramping and we will talk about that. It is not a straight line growth rate at all, it is more an exponential growth rate. And one of the metrics that we looked at is that, prior to Hurricane Katrina in 2005, the shale gas is ramped up such that total onshore-only production now equals the total U.S. source supply prior to Hurricane Katrina. So accounting for about 10 bcf that is produced in the gulf region, you can see, since 2005, the kind of growth in the shale area -- unconventional shale area. And we also found that the recoverable resource base, then, is not constrained. This was something that the industry was operating under, we felt, and a lot of folks were falling into over the last five years or so, that maybe we were running into a peak kind of situation on the natural gas side. Our findings certainly were not that, and that what this study discovered was that the domestic ultimate recoverable resource base in the country was between 60 and 80 Tcf and 2,247 Tcf, or on a yearly basis, based on 2007 production levels, enough supply to meet the market at the high point, 118 years. We also found that most of the supply development is located within the shale area, and that is another finding we will talk a little more about.

So this is from the study itself, that the U.S. production rate reached 19.3 Tcf/year by the end of 2007, this is overall, a 4.3 percent increase over the prior year at the end of 2006. Then, the production from unconventional sources actually increased from 1998 to give one an idea of 5.4 Tcf, to 8.9 Tcf in 2007, a growth rate of 65 percent over that period. Unconventional production increased from a total of 28 percent of the total U.S. production to a level of 46 percent in 2008. Looking at onshore production and distinguishing it from the offshore production is also important, and really the focus of our study, that by the end of 2007, onshore production was up about 4.4 percent over the prior year, and this was according to the EIA average onshore production for 2007, exceeded 2006 by about 5.32 percent. If you look at the chart, what we are showing is that, since 2005, this chart was just constructed from 2005 to the first quarter of 2008, there was a compound annual growth rate of 6.1 percent over that period, a growth rate that is healthy by anyone's standards. And playing to the point of what our finding was, the growth is not straight line by any means. One of the metrics that is hard to get a hold of, but which we used, was that in the first quarter of 2008, growth had been even more pronounced where, year over year, the growth rate in the first quarter of 2008 were 11.49 percent year over year. So this accelerating growth was consistent with what we started to hear from the producers and what was our sense as we went into this study at the outset.

There have been some changes also and folks are seemingly listening and looking closer and starting to get a handle at what really had been happening, and what was not well-understood up to this point. EIA in their AEO '09, a lot of people will note, have dramatically increased their unconventional gas supply and their shale gas. We still think that those forecasts are conservative and that has been the history of some of the forecast out of EIA over the past.

So the basic findings were that there is continuing unconventional gas production and reserves growth in the U.S. We are still, as mentioned -- and this is a bit of the update -- not having full access to data for the year 2008, this is trying to bring this forward to today, but what we are seeing is anecdotal, and we will mention it as such, evidence from the producing industry again -- and other sources -- we are highlighting a few here -- that it appears that shale gas is very alive and well, and this growth in the shale area will continue. Southwest Energy had a net production of 134.5 Bcf in 2008, compared to 53.5 Bcf in the year previous, and this is from the Fayetteville Shale, this was announced in South Western Energy's Annual Report just recently. Range resources expects to triple the Marcellus production in 2009, with a target to exit the year at 80-100 MMcfe per day, and this also was released in their 2008 Annual Report. Petrohawk Resources increased reserves from just a little over 1 Tcf to 1.4 Tcf, mostly through shale properties and mostly within shale, although they have some other production, and this was announced in an April Investor presentation. Quicksilver Resources, another active participant in the unconventional gas area increased production from 201 MMcfd in Q1 '08 to 332 MMcfd in the first quarter of 2009, a 57 percent increase in production, as in their press release May 6th of this year, not too long ago. Devon Energy, the largest producer in the Barnett - Barnett, we will talk about a little more, increased net production there to 1.2 Bcf and announced that in the first quarter of 2008, the production a little bit dated, from just .99 Bcf a day in the year previous, and this was in a press release. So we are getting the sense of the kinds of things. There are other announcements, XTO and others, that also are announcing some very -- and we are watching closely -- some very exciting additional production growth numbers from the shale area. So this is one of the points, and I am not sure what has happened with the chart here, but we do not want to make too much of this, and cut EIA a little bit of slack because they are not alone in terms of forecasters trying to stay up with, really, this paradigm shift in the natural gas area with respect to shale. But the history is that there has been a chronic historical underproduction of gas supply, most recently -- some of you might have seen yesterday, the EIA came out with a short-term energy outlook that, again, forecast short-term production growth as being less than what they had previously been announcing. So we just wonder as to whether some of the thinking is not continuing. But what we did see in the EIA 2009 is that U.S. domestic gas, and according to the EIA's forecast, they increased by 43.5 percent for unconventional gas, including shale. And this is in 2030. We were happy to see that. So we maybe are making some inroads to folks that are looking at this closely, and since our study there has been certainly some very good work that has been done that are, in all cases, supportive, that we have seen, to the base findings of our report.

There are still a few questions here. We will cover some of those and look forward to having a discussion on that later today, but can this continue? Can the resource base support it? I will address this more in detail, I expect, later today. But we think that the rate of growth is certainly continuing in the short-term; in the long-term, it is to be determined. No one tells -- we do not even pretend to be the soothsayers of the industry, but we see the evidence. And in terms of the resource base being able to support this growth, we believe very clearly, so our answer is yes on that and we will talk more about that and look forward to discussing that more as we get into the end of the discussions later today.

This is a chart that shows several things, and we are seeing a lot of misunderstanding, perhaps, by the industry in terms of drilling statistics. We think that the metric of drilling statistics and the declining rig count in the gas area is something that needs a word of clarity. Firstly, shale is not about anything really other than horizontal gas. There is some shale that is delivered by vertical drilling, but if analysts are looking at merely gas drilling statistics, they are not reading the right metric. What we have seen is that, in the gas drilling area -- this is the yellow to orange part of the slide here

-- there is no doubt, it has been well reported that the rig count is down, the vertical rig count is down 66 percent, 262 rigs in April to 24 from the peak of 781 for the week ending July 4th 2008, which was the peak for the industry. Horizontal rig counts, though, which is the red part, you can just see going back to January 2008 to today, it is pretty darn flat. What we are showing is that the horizontal rig count, which we believe is more important for people following the activity in the level, is giving you a better indication of what is apt to come and what is the focus of the producing industry at this point in time. And we also -- in the top two lines, this is the important part of the slide -- is that there are two lines here, EIA's own numbers and Lippman Consulting numbers that show that production is pretty darn flat, actually ramping up a little bit over this period from January '08. So, to date, we have not seen a decline in U.S. dry gas production impacted in any way by drilling rig counts, so we wanted to make sure that we made that point today, we think it is important.

So I touched on this, but a key finding of our study was that the Potential Gas Committee, which is an industry group and sponsored by the Colorado School of Mines, also had the last -- in their 2006 report -- a fully analyzed report on the reserve situation in this country. In their report, they were listing in 2006 -- a lot happens since then, this is what we are saying -- is that the resource estimate at that time was 1,530 Tcf of reserves, and using 2006 production rate, that translated into about 82 years of gas supply, pretty robust. Our mean estimates were higher than that. As we went about our study, on a mean basis, our estimates were that the total resource base was 1,680, or 88 years of supply, based on 2007 production numbers. We believe that these numbers are very very conservative. At the maximum end, and this is what is most widely reported, and perhaps rightly so, that our reserve estimate was 842 Tcf of reserves. This is based on information we are hearing from producers again. Based on those numbers and 2007 production rates, it would amount to 118 years of reserve life of the resource here in the country.

So here we are looking at what -- Barnett was identified this morning as the granddaddy of the Shale industry, and certainly rightly so. A lot of information has been learned from the Barnett, and those folks that are involved in the Barnett play are using that information as they go about developing other shale plays throughout the country. It is just an amazing situation here when you do look at some of the numbers. What you are seeing is a production growth from 1998, not too long ago, to from basically almost no production, .94 Bcf a day in 1998 to over 3 Bcf a day in 2007, which we announced in our study. And this is an increase of more than 3,000 percent over that period. The latest production figures are even higher than that, 4.6 Bcf a day, or 8.1 percent of U.S. production from that one basin. What a sweetheart of a play it really is. There are other plays that are contained within the major basins at this time -- Fayetteville, Haynesville, and the Woodford. They are all showing continuing signs of ramping up. Marcellus, touched on this morning, and more discussion on that, I am looking forward to here shortly, is out there and there is more good things likely to come in terms of Marcellus. This is not an accident that this has happened, it has been a technological breakthrough, there has been a paradigm shift, there has been something that has happened in the industry on the technical side that has combined two old techniques, actually, hydraulic fracturing, it is not new, it has been around for a long time, with horizontal drilling. It is really the combination of those two technologies that has made shale what it is today. We heard some of the geology and the reasoning behind that this morning. There will be more discussion, I expect, as we go along. But there is a reason why shale is doing what it is doing in this country and elsewhere today. Producer estimates, the big six, plus Marcellus, come up with estimates of eventual production from the shales of 27 to 39 Bcf a day upon full development in 10 to 15 years. This slide here talks about that and we get to 2015, what we are submitting here is that, some of the risks that the industry is looking at very closely these days is that, at these kinds of level, and assuming the kinds of rates of growth in the industry, will there be too much gas in 2015 based on the current market conditions of 58 Bcf a day, roughly, 27 Bcf just from these select basins, not taking into account anything new, any new basins, or any continued ramping, if that was to continue in the shale plays, it likely results in this market having too much gas.

So this is really hard, but this is important to try to get one's head around as to really the size of this development in the industry. And we want to throw out a couple of things here, that try to look at this in a sense as to what is going to perhaps be the solution, the ongoing solution for the industry from a supply perspective, if we are headed toward a over-supply, and here is a couple of metrics. The EIA 2009 forecast of the lower 48 onshore gas supply was 44, take my word for it, Bcf a day. We forecast the lower eight onshore gas supply in 2020 as to about 59 Bcf a day, there is a forecasting difference here between what we are seeing and what the EIA's forecasting of about 15 Bcf a day. What is 15 Bcf a day? How big is that? Well, looking at a couple of markets that are a matter of discussion in many circles across the country, are using the EIA's numbers of U.S. diesel transport fuel of just over 20 Bcf a day, equivalent in 2020, 15.4 Bcf could displace more than 75 percent of this amount. The EIA also forecasts coal demand for electric generation to be 10.5 Bcf a day equivalent in 2020 -- this is a growth number, then -- a growth number between 2009 and 2020, and this 15.4 Bcf could displace 100 percent of the electric generation coal growth, and leave about 5 Bcf a day for vehicle fuel, which could be enough to serve 10 percent of the current U.S. vehicle fuel needs. 15.4 Bcf, looking at it a different way, also represents 21 percent of the 2008 listed annual coal demand in 2008 of 73.7 Bcf a day, enough gas to serve 20 percent of the coal generation market.

So here is what we are looking at, and this is a slide that was used in several presentations, it seems to be a popular slide these days, we have added on California because what -- this is the same, these basins are in 21 shale basins, there are over 20 states very widely dispersed, actually, and it includes the biggies, but then in California there are two basins, the Monterey and the McClure, within the San Joaquin and Santa Maria basins, that our potential gas shale plays. We do know that there has not been a lot of work in that area, but we wonder if it is just not at the cusp, and that eventually we will start to see some developments in California; certainly by aerial extent, the area is large.

Turning to implications of what we have found is that essentially you have got an interconnected grid of gas supply throughout North America, you have got some other factors in terms of trying to drive this market toward a world market, a global market with LNG, but focusing for the present on the domestic effects, you can see in this slide that what you have is the location, the Mid-Continent area of the big shale basins, as we define them now. And we also look to the Northeast to Marcellus, and Antrim in Michigan, certainly. But you see a potential for the direction of the gas load to head to -- it seems to be well situated geographically to serve those markets in the

Northeast. Well, at the same time, a metric that will play back into the California market is through an indirect source with Rockies Express Pipeline, some would say from a California perspective, it is taking gas away from the Rockies and delivering it to -- like to get to New York with it eventually, we will see if that happens. But before that may occur, there may be gas that is in New York, and the Marcellus play starts to develop and they have a word to say about how much Rockies gas is actually delivered in the Northeast. We see that as a dynamic, when you have an interconnected Pipeline grid like we have in North America, we can see things change fairly rapidly, and with the growth of the shale plays, there is a potential to eventually end up with gas supply, and we are now seeing some pipeline developments that perhaps are thinking along the same lines, that if there is more gas in the Northeast out of Rockies Express, then maybe additional gas from the Rockies that is available to head this way, toward the West, Kern River seems to be in a pretty darn good position to be able to take advantage of some of this Ruby Pipeline, other pipelines that are proposed to California. There is a California angle on this.

So now, looking forward here, you know, if we are heading toward too much gas supply, that is what we are heading toward, then what might happen? What should happen from a balancing perspective? And we point to a couple things, a few things to be able to try to get our arms around this, is that what we are seeing today, and looking at history, is that in an era of high prices, usually there has been a decline in demand and, in the converse, that in a period of low prices, gas demand has flourished. This is not maybe a too surprising metric, that buy low, sell high, kind of thing.

Another dynamic potentially affecting gas demand is climate change, and concerns over carbon and other greenhouse gas emissions, certainly an issue today, we believe, and we also think that, as we project forward, that overall developments along these lines are expensive for natural gas demand. And as time goes along, we will start to -- and the market will start to understand that basically, natural gas is clean, and it is plentiful, and that will probably translate into a marketability that will be positive for gas demand going forward.

Climate change policy, then, we see as possibly -- certainly an increase in gas demand and despite, perhaps, higher prices. We look at prices, we see what they do. One thing that we are pretty certain is that prices will not remain the same.

So this abundance, from a picture of abundance, and this is the message that has come across to a lot of industry and non-industry proponents, is that this abundance, this shale, seems to be well positioning for the gas market to be able to serve new markets. And what we are looking at, in particular, and observing and participating to some degree is that natural gas seems to be well-placed to serve an increasing share of the vehicle fuel market in the country. In the state with the largest number of vehicles in the country, we also think that there is a role for natural gas in the vehicle fuel market in California. Using the CEC's own statistics, there is a benefit in more natural gas in the heavy truck sector, in particular, in California. We see also that, in terms of another market area, in terms of energy competition in the electric generation market, that coal -- there is a gas price competition that is occurring right now, gas straight up with coal and certainly over the winter we saw some coal markets that were taken over by natural gas.

That is my presentation.

COMMISSIONER BOYD: Thank you. I think Ms. Brown has a question or two, and then I have a couple.

MS. BROWN: Yeah, Gordon, it is obvious that you are bullish on natural gas and on gas shale, in particular. Am I right? Could you comment about the relative cost of shale gas vs. conventional gas, in terms of extracting and developing the resource? That is one question. And I guess the second question would be, how does the current economic situation affect the willingness of private industry to continue to invest in shale gas?

MR. PICKERING: The second question first, I think you can look to some of the statistics in terms of horizontal drilling to give you a clue as to what the industry thinks of shale. We see flat numbers of horizontal wells being drilled year over year, and I think in this environment where the overall gas drilling has just been very dramatically affected, that gives some sense that the industry is diverting a major part of their development dollars into gas shale. So I think there is a message there that the industry sees shale as something that is economic, likely, and is also perhaps their future looking forward.

In terms of the economics and pricing, that is a very complicated subject matter, first of all. It is complicated and I had intended to perhaps talk about this more later on this afternoon, but I just want to mention a couple of things that makes it more complicated is that the economics of production economics are complicated by regions, by the geology, by the producers themselves, and timing. Certain producers have been able to acquire a first mover advantage position in certain plays, that has always been the case and it is the case, certainly, with shale, where their costs -- land costs, in particular, their exploration costs put them at an advantage vs. others that are coming lately into the plays. The other factors that have to be considered are certainly the market and market conditions, and they will vary, and there is marketing attributes to certain producers where the market prices are not in all cases what producers are looking at when they produce gas. They have sometimes sold forward through hedging programs, etc. So you put this together and you have got a complicated situation, but not to skirt the issue. We believe in large, and in total, that prices that are sustainable, that provide for sustainability in the marketplace, are somewhere in the $5.00 to $7.00 per Mcf range.

MS. BROWN: Thanks.

COMMISSIONER BOYD: Gordon, thank you. Here you go, three questions, one, why -- or do you have a view, even, on why so many people were surprised, it seems to me, in a very short period of time, that there was all this shale gas supply. I mean, it seems to me around here, even in the last nine months to a year, maybe, by now, even though Leon said we have known about shale gas for a long long time, it seems an awful lot of people -- and I hear this from lots of quarters. A lot of people were caught off guard by the sudden revelations of so much potential gas supply, which is probably why earlier on I said, you know, in my limited time, I have gone from feast to famine and back to feast. And it just -- I wonder if you have any views on that. Secondly, and some of this may be related, your views on -- do you take into account when Alaskan gas might get here? And thirdly, I am just going to comment that I was just introduced to an Alaskan gas project from a North Slope -- not an oil project, but a gas project -- where drilling one well is going to cost $290 million. They are going down two miles and making a right turn, and going out eight miles to get to this stuff. That seems outrageously expensive. You commented too much gas supply issue hanging there. I wish I had known all this and could have -- I did ask, I mean, you obviously see the economics there, and they said yes, and I was not prepared to throw any of this data at the folks. But I do not know if you had any views on -- it is, again, kind of the economics question that Susan raised.

MR. PICKERING: That is a surprise. That is a surprise. Partly, the reason for the surprise is the way that we collect data in the industry. There is a built-in lag between getting the facts, getting data from the producing community to the reporting agencies, and that, we have got a lot of jurisdictions that are involved in this process. So there is a data management issue here that comes into play, that have a built-in lag to it, that is part of the reason why something that is developed as rapid as this -- I mean, this is something that you cannot wait a year and expect that you will not have missed a substantial development; there is that part of it. The other thing is that you must remember that the producing sector is a competitive industry. Some of this information needs to be properly -- properly -- and I say a lot by saying that, but it needs to properly be kept within the -- it is proprietary information that producers need to keep and want to keep within their own purview. It is competitive advantage at times, so if this is where -- we certainly face the challenge with our study. How do you really get to the facts without disclosing proprietary information, and therefore advantaging somebody else.

COMMISSIONER BOYD: It was the pipeline people who really gave us, I think, the first hints that something was going on out there, without us knowing, gas suppliers, that this was the breakthrough. But in any event…

MR. PICKERING: Pipelines are pretty close to the horse's mouth, there is no questions. But their producers have the information at the outset. In terms of Alaskan gas, that is a tough call. I mean, and it is also a subject for considerable discussion. I will tell you that, in our forecasts, we no longer are forecasting McKenzie within our gas forecast. So the McKenzie Valley Pipeline is not included in Navigant's long-term forecast. We think that there is some -- the Alaskan Pipeline project, we still are including production being delivered to the lower 48 and in Alberta, but the Alaskan gas even may have some options. People are looking at a bunch of creative things these days, so frontier supply and how it enters into the North American supply-demand mix is something that we think is really a moving target, and will be part of the more complicated economics of the industry going forward than it has in the past. $200 million per well, if I heard you right, you know, even in an industry like the producing sector, that not always, I will say, pays attention to economics on a per well basis, or even on an effort basis, that is a lot of money for a well. Now, what you have not said is, "What is the carrot?" So without looking at what these folks -- what they see, or what kind of program could we develop from this, really, a pretty difficult question to answer. It sounds expensive.

COMMISSIONER BOYD: $290 million or $300 million, right?.

MR. PICKERING: Yeah.

COMMISSIONER BOYD: And there is not even a pipeline yet, so it defies --

MR. PICKERING: There is something -- if this is real, there is maybe something else there that we --

COMMISSIONER BOYD: These are not wildcatters, this is BP, it is a well known project, I just cannot remember the name of it all of a sudden.

MR. PICKERING: I see.

COMMISSIONER BOYD: Okay, well, thank you very much. Ruben, you and Suzanne are looking real nervous over there.

MR. TAVARES: Yes, we do.

COMMISSIONER BOYD: I feel it has something to do with the schedule.

MR. TAVARES: It does, Commissioner. We have scheduled one more presentation before luncheon, and actually it is coming from a Professor at Pennsylvania State. If you do not mind, I would like to go forward with that presentation.

COMMISSIONER BOYD: Please do.

MR. TAVARES: Okay, next we have Professor Terry Engelder, from Pennsylvania State. He is the leading authority on the Marcellus gas shale. He is currently a Professor of Geosciences at Penn State and has previously served on the staffs of the U.S. Geological Survey, Texaco, and Columbia University. He has written over 150 research papers, mainly focused on the Appalachia. He has worked on exploration and production problems with companies such as Saudi Aramco, Royal Dutch, Shell, Total, and Petro. Professor Engelder, are you there?

PROFESSOR ENGELDER: I am, indeed. Does everyone hear me.

MR. TAVARES: Oh, perfectly. Go ahead. You have about 25 minutes.

PROFESSOR ENGELDER: Well, thank you very much. I am pleased to be here to offer some thoughts about the Marcellus shale, first of all, but I think more importantly the overall North American natural gas business and where we are going. I think the previous speaker, of course, hit it on the head. And I, too, am very bullish on natural gas in North America. Now, if you listen to me, you must remember that I am a Geologist, not a businessman. I do not have a stake in Wall Street, really, on this. I have watched this development in the natural gas business for on the order of 30 or 35 years and, in fact, it was a press release out of my university, Penn State, on the 17th of January 2008, that probably marked this paradigm shift in which the nation, or at least the Northeastern part of the nation, became fully aware of gas shales. And yet I was aware, for example, that in 1940, a well was drilled in the Appalachian basin. It was drilled to reach a conventional reservoir called the Oriskany Sandstone, one of the largest gas reservoirs in the Northeastern United States. And to reach that, one had to drill through the Marcellus and, as the drillers were going through the Marcellus, there was a huge blow-out; in the period of the next four to five days, 60 million cubic feet blew out of this well from the Marcellus. This is probably one of the first indications that the Marcellus really had tremendous potential. Now, bear in mind, this is 1940, so someone asked the question, "Why have we been surprised or blindsided by natural gas?" I think, from my point of view, it was not really all that surprising. And, in fact, it is that kind of insight that probably led to the Penn State press release and sort of turned the paradigm. One had to be watching for this length of time.

Now, I should point out, even with the EIA assessments, which have been conservative, during the Jimmy Carter Administration, when the Department of Energy was initially set up, there was a very large gas shales program called the Eastern Gas Shales Project. And if one looks back at the literature during this Eastern gas shales project, one sees a resource calculation not quite as large as they are today, but nevertheless trillions and trillions of cubic feet of gas in place were predicted. What really happened, I think, was the industry in general, and the public, forgot about this, or this retreated into the background. Bear in mind, this is the Carter Administration day-to-day from the 1970s, they were there for everyone to read if they wanted to. So, at any rate, that is a little bit of the background.

Now, today I want to talk, first of all, about the Marcellus. And, let's see, Helen, I am not in control of this.

MS. (UNIDENTIFIED SPEAKER) - Actually, yes, we gave you presenting rights, you should be able to --

PROFESSOR ENGELDER: Yeah, what do I do, hit "Enter?"

MS. (UNIDENTIFIED SPEAKER) - Hit your down arrow, and you should be able to move into the next slide.

PROFESSOR ENGELDER: Hit the down arrow, okay, great. Thank you, Helen. I am sorry, folks. All right, so the questions that were posed to the California Energy Commission, particularly concerning gas shales, include -- and I have here seven bullets, and I want to address -- actually six bullets -- I want to address three of these: can future production of natural gas from shale formations meet expectations of the gas industry? And, like the predecessor, I would say yes with an exclamation point. I will explain this a little bit more; Are the current gas shale reserve estimates reliable? And there I say 'no', and they certainly can be improved. And the point was well made, and I will reiterate it, which is that, in general, the government forecast, which included EIA and the potential gas committee, have tended to underestimate the reserves, and largely this is because these estimates are based on production. And in the case of the Marcellus and the other gas shales, if we go back 10 years, there was no reduction from those particular gas shales, and hence one would not be surprised to find that these organizations did not make the prediction. There are a couple of other questions. I am going to skip the two in smaller type and look at the one in italics, "How might potential environmental impacts affect future drilling and production of natural gas from shale formations?" The brief answer will be the same as the preceding speaker, which is that I think the whole climate change and the demands of the total climate change will serve to focus industry more and more on natural gas, favoring natural gas over coal, for example. Finally, is gas shale a viable long-term source for natural gas in the United States? And this is yes, emphatically. In fact, the reserves are so large right now that I believe that long-range planning by a state government, the national government and industry, energy producing industry, for example, can be made based on the fact that these exist.

Now, one of the questions came up during the previous question and answer session concerning conventional gas vs. unconventional gas, and it is important to point out that conventional gas discovery and production is in decline. There is no question about that. And it will never be replaced with other conventional gas.

Unconventional gas will replace it and it will replace it, as the previous speaker indicated, exponentially. The discovery costs, this is a very important point, as well, which is that conventional gas reservoirs tend to be spied, they are here, they are there, one explores for them, one pokes around, a well might be drilled here, an innocent well drilled over there, and hit. The unconventional resources, and this includes the Barnett, the Fayetteville, the big sediment through the Marcellus, all of them by virtue of being unconventional, are continuous reservoirs where there is less risk in terms of exploration, less money is spent in mining costs, for example, and this really really produces the overall cost of this particular gas relative to conventional gas. So America has really been blessed in this particular regard.

All right, again, it is important to understand that the reserves classification -- I am assuming some of the audience understands this, and if you can bear with me for a minute -- the old EIA forecast, even more so the U.S.G.S. forecasts, are based on a P90, proven reserves. Basically one proves the reserves through production. And these numbers are the numbers that tend to be low, these numbers derive some of the government forecasts. What we really care about in terms of looking into the future are these unproven reserves, particularly probable reserves. And when we make a prediction that there is somewhere on the order of nearly, oh, 1,680 to 2,240 trillion cubic feet in America's future, these numbers are closer to this P50 estimate, rather than the P90 estimate. If one really wants to get excited, boy, then one can look at the P10 reserves and really inflate the value of what you might be looking at.

Now, gas forecasting is a little bit like weather forecasting. One can think of a proven reserve forecast as being short-term forecast. Really, we want to look at long-term forecasts because these are the types of forecasts that one can administrate policy by. And I want to talk a little bit about this P50 regarding the Marcellus play.

Now, first of all, in terms of the short-term forecasts, the last ranking by EIA, the crude reserves have actually been two or three years ago, this is a website dictionary I pulled up actually within the last week or so, and the interesting thing is that the top ranked field is the San Juan Basin. Notice the number two field here, Newark East, that is the Barnett. So what this means is that in 2006, the Barnett had actually started to score big time in terms of production. But if you look at all of the other fields right in here, by and large, they are conventional fields. Now, what has happened in the last three years is that these unconventional fields, 1, 2, 3, 4, and 5 have all been replaced by the unconventional reservoirs, so that if we were to look at the same EIA maps now, one would see that Haynesville, Fayetteville, Barnett, and what not emerge at the top. This is how fast the paradigm shift has taken place. And when one thinks about California gas supply, then the closest source is, of course, these fields from the Rocky Mountains, including the Green River Basin, the Denver Basin and, in fact, these are the gas fields that direct the pipeline going both east and west. And in terms of looking at energy in California and making some long-term plans, really, the question is can gas fields in the east, and particularly the Marcellus, sustain the east to the point where almost all of this gas production in the Rocky Mountain Region can be turned around and aimed toward the west? Now, probably that will not happen, but certainly we have seen examples of this being turned around, that the southern pipeline, for example, through the El Paso Pipeline, as you heard earlier, has suddenly started carrying more gas to the west. And with the development of the Marcellus, there will be a larger tendency to take this particular area of gas from this area and aim it elsewhere. Now, the EIA map for the Eastern United States looks rather lonely. Here is the Antrim plate right there, but certain in 2006, no one imagined what the Marcellus would amount to. And you have seen this obviously several times today. I think one of the most important points here is that the volume of the Marcellus is just overwhelming relative to any of the other gas shale plays in North America. In fact, if you start looking at the size of gas fields internationally, at least right now, the Marcellus in terms of potential production, that P50 number, the Marcellus is the third largest gas field in the world. And that certainly will have an impact on distribution of gas in the next number of years, and will have an impact on long range planning of the impact. So how does one go about forecasting the amount of gas that is in the Marcellus? Well, we have to look to the Barnett example. And in fact, if you look at this data compilation right here, what we really want to understand is the amount of gas to the particular well is capable of producing, so on the horizontal axis you see the label EUR, this is Expected Ultimate Recovery for a particular well. Each of these data points represents one well in the Barnett.

There are 4,000 of them shown here. And what you see on the vertical axis is the amount of production in terms of millions of cubic feet a day, and this that occurs right here represents, then, an attempt to make a long-term prediction based on initial production rates. Now, one of the interesting things about the Marcellus, particularly in Pennsylvania, is that Pennsylvania laws differ quite a bit from many of the other gas producing states in that the operators can hold production data, proprietary, for five years, so that one has to make some estimates based on other gas fields. And so we will use the Barnett.

Now, you will notice the slope of this line for vertical wells here is one in which we can see that the Barnett, the Barnett well that produces a million cubic feet a day, for example, will ultimately yield 1.5 bcf. The horizontal wells for the Barnett are what we really care about. In this upper curve right in here is that curve and there is a general rule of thumb in industry right now that a horizontal well producing a million cubic feet a day ultimately yields a billion cubic feet, so there is that 1:1 relationship, three orders of magnitude.

Now, the average horizontal well in the Barnett and the average horizontal well in the Marcellus yield quite a bit more than a million cubic feet, so these are incremental units. And now we turn to the 2008 production records -- now, bear in mind again that each company hold their production cards close to their chest, and so what we have to do is rely on quarterly calls from industry, and so the data you see right here are announcements of initial flow rates from a number of the companies across the Marcellus play. And what you see, for example, at the Southwestern corner of the map is a range of resources welled in an amount that flows at 24.5 mcf a day, a very very large well. So over the last year, with a little bit of work, one can compile the IP's for a number of the wells through 2008. I could account for on the order of three-quarters of all the wells that sputtered during that period of time in Pennsylvania, and when one does that, then one comes up with a probability distribution function that looks like this slot right here; what you see, then, is the log on the vertical axis, it is a Log Initial Production, and on the horizontal axis, this is the percentage of wells that have an IP that is less than a certain number, for example, that production of 24 million a day, virtually every well on this plot flows at a lower rate than that.

Now, one of the few things that are actually emerging, that has become evident only within the last two to three to four to five months, is that the average Marcellus well is ending up performing better than the average Barnett well. The reason that Wall Street is really excited about the Marcellus, the reason, for example, that the Appalachian basin in Marcellus is the only basin where the rig counts have not decreased at all through this entire economic downturn the last six to nine months, is this combination of facts, which is that right now it appears the Barnett, the average Barnett well, is not going to be quite as good as the average Marcellus well. The volume of the Marcellus is somewhere on the order of four to six times the volume of the productive Barnett, so that there is an awful lot more gas in the Marcellus. And, of course, the Marcellus is so close to the Northeastern market, one of the best developed and most advanced gas markets in the United States. So all of this is really fairly exciting.

Well, one can then put down some EUR for the Marcellus -- in the case of the Marcellus, they are based on an initial production data only -- and then one can do what Steve Drake here did for the Barnett, which is that you break this down into regions or on a county-by-county basis. Some counties in the Barnett perform better than other counties, and the same is true of the Marcellus. And so as a Geologist, what I did was I sat down and took the 117 different counties in five different states, that have productive Marcellus, and I ranked them to rate them in certain years. So if you want to understand this set of curves, which is that we have a lot of data for the Barnett, we have little for the Marcellus, but what we have indicated, the Marcellus will perform better well for well. But we can tier the Marcellus through 117 counties, which I have done right here, and when one grades the Marcellus, then one can produce this type of data right here, which is the bottom line. I have now ranked the potential production of the Marcellus through its five state area. You see that this is a risk potential for the Marcellus. Now, what risk means is that it is assumed that only 70 percent of this continuous reservoir will be accessible; for example, no one is going to drill a well in Three River Stadium where it is where the Pirates play on that very rich land that is where the Pittsburgh Pirates play on, they are not going to have it. There is topography to deal with in the Marcellus play other than which will limit the accessibility. This also assumes 80-acre spacing. Now the industry is very very rapidly in the Barnett, and even in the Marcellus, moving to closer spacing as gas is being recovered from the play. And this represents a recovery factor right now that is on the order of about 10-15 percent. If that recovery factor gets larger, these numbers go up quite a bit. Right now, the last time that I was interviewed by the Associated Press, I announced a P50 for the Marcellus of 363 trillion cubic feet of technically recoverable gas; you can see that even going up right now. I will publicly at least tell everyone, 363 trillion cubic feet. That is a lot of gas, given that the United States consumes somewhere on the order of 20 trillion cubic feet a year. And you can see in one of the recent Tristone Capital Reports on the Marcellus, they predicted 1.2 quadrillion cubic feet of unrisked Marcellus gas, recoverable gas. This is not gas in place; in fact, the gas in place in the Marcellus is somewhere on the order of three to four times this large. This is a huge huge field, and will have a bearing on the way that the country proceeds from here in terms of developing an energy policy.

Now, I like this diagram produced by Bentek. They identify the Northeast as a Northeast Wave Constraint, basically, which you can see right there, is that is the offensive lineman of the Marcellus play right there, ready to block anyone that is coming from the southern western part of the country. I am using that particular analogue. I think that, in terms of planning in California, this is the image that I would like to leave you with, and certainly it is consistent with the previous speaker who indicated that there will be a tremendous pushback from the Northeastern United States, and what that is going to do is actually redirect that Southeastern Gulf Coast bubble, and in fact turn that around. It will certainly turn the Rocky Mountain gas around. And how far the Marcellus reaches outward is going to be hard to predict; obviously the Chicago and Michigan markets will still be very good, probably consuming gas from the Rocky Mountain region, but nevertheless, there is going to be -- there is going to come a huge Quebec from the eastern half of the country that includes all of these big gas shale plays. One can, I think, make some long long range decisions about energy policy based on this particular scenario. It is very real, it is a paradigm shift, the previous speaker has mentioned, that really will govern a lot of what we do in the future. And I have already stolen this under -- this is list of the top eight gas plays in the world. You can see that Russia is still [inaudible] long future. Haynesville is in there with the Marcellus at 3 and 4 right now. So, at any rate, I certainly would be pleased to answer questions and I certainly thank the audience for their patience, particularly through that tape change.

COMMISSIONER BOYD: Thank you very much. This is Commissioner Boyd. Thank you for the presentation. Let me see if anyone here in the room has a question they would like to ask of you. Here comes a gentleman to the podium.

PROFESSOR ENGELDER: Please identify yourself by name and where you are from because I cannot see your name tag.

COMMISSIONER BOYD: Most of them have been very good about that. Up here at the Dais, I have been pretty bad about saying who is speaking, so --

MR. WAYNE: Yes, Dr. Engelder, this is George Wayne with El Paso Corporation. Can you hear me?

PROFESSOR ENGELDER: Yes, I can.

MR. WAYNE: A couple questions. One was just I wanted to get clear on the difference between technical recoverable and old estimate ultimate recoverable. Are those interchangeable in your mind? Or is there a difference?

PROFESSOR ENGELDER: Yes, they are. They are different. And there are two or three ways of assessing a resource. The way of doing it prior to production is one estimates the volume of capacity, depth, of thickness, or core pressure, and from all of these perimeters, then one comes up with some number based on a recoverability factor. And then one says, "This is technically recoverable gas." The ultimate, the estimated ultimate recovery, is based on true production data. And so when the Penn State press release came out in January of 2008, talking about the Marcellus, there virtually was no production made, and so that press release was based on a technically recoverable estimate, the way that I have indicated, it is a volumetric calculation. Then, when I was re-interviewed by AP, the Associated Press, later on in the fall, we had enough production data where companies had announced what they were doing in their quarterly calls, so that you could then start to make some estimate of the EUR, Expected Ultimate Recovery, and at that point put this in a statistical framework so that, basically, I think the simple way of thinking of this is that the technically recoverable gas, there are no statistics attached to that, whereas in this estimate of EUR estimate, that is statistically-based, and obviously a lot more robust in terms of looking into the future.

MR. WAYNE: I see. Thank you. With regards to that, you know, you see whether it is EUR, estimates, or technical recoverable estimates, you know, there is the possibility for gas-in-place and obviously the difference between gas in place and technical recoverable can be a third or a quarter of that number.

PROFESSOR ENGELDER: That is correct, yes.

MR. WAYNE: And for the --

PROFESSOR ENGELDER: Oh, wait a minute, wait a minute. The third or the quarter, the gas-in-place is all that is there, the technical recoverable is one-third to one-quarter, I am not sure if I heard you.

MR. WAYNE: Yes, yes, that is what I mean. So given the Marcellus in that regard, I do not know what the range is, if it is going to be a third or a quarter, but what does that roughly put sort of your peak production at out of this resource? In other words, because it is producing less than maybe 100 a day now, but ultimately what do you think the pink would be in where that would occur?

PROFESSOR ENGELDER: I cannot even give you that number. It is going to be relatively large. I do not know where this is going to in terms of the peak production. But it is going to take a while to get there. And I do not even know what I mean by a while. I do not know whether that is five years, or 10 years. The reality, of course, is that Pennsylvania, in terms of infrastructure, there are some challenges there. And peak production probably will depend as much as anything on getting the infrastructure in place, the speed with which that happens. And dealing with the water that one needs for these massive hydraulic fractures, it is a very interesting thing for us, I am talking Alaska, Pennsylvania, has more stream miles than any other state in the nation, so Pennsylvania is blessed with lots and lots and lots of water. But unlike Texas, for example, which has relatively young geological formations in which you can drill a lot to disposal wells, in Pennsylvania, the rocks are older and a lot higher, so that the disposal issues still have to be developed right in here, and I would think that TVP production, as much as anything, is going to depend on infrastructure and the disposal issues, and if you had to ask me, I would force the answer with one of those two is the rate perimeters -- I think probably disposal needs will be the rate perimeter.

MR. WAYNE: Okay, and then one last question has to do with -- you did not touch on this, but something I have been curious about with the shale plays, in general, vs. your conventional drilling. Because the decline curves are much steeper in the shale plays, at least that we have seeing based on the Barnett and Haynesville-type curves, what do you think that means in terms of basically the intensity of drilling necessary to keep production flat as we go through these business cycles?

PROFESSOR ENGELDER: Well, there is no question but what the initial decline is fairly steep, but once the decline levels out, it is somewhere on the order of 10-20 percent of the initial production, why then that wells run forever. So basically, if you have one well coming on in an initial rate, in a decline of 20 percent within the first year, then one has to keep drilling on the order of four additional wells that year to replace that initial flow, until you have enough wells that have reached the flat part of the decline curve, which is 10 to 20 percent the initial flow. And so the rate, at least initially, of drilling to replace that deep decline will have to be relatively healthy in itself. And I do not have the numbers, though. I have not reviewed that.

MR. WAYNE: Well, thank you, doctor.

COMMISSIONER BOYD: Any other questions from the audience? Well, thank you very much, doctor. That has been most interesting.

PROFESSOR ENGELDER: I appreciate being able to help you out.

COMMISSIONER BOYD: Ruben, it is yours.

MR. TAVARES: Thank you, Professor Engelder. I understand, Commissioner, that you are late for an appointment?

COMMISSIONER BOYD: Yeah, I am late for my noon meeting with the Chairman and a bunch of staff, so I am going to let you moderate what is left and then break people for lunch, and then come back at what -- I guess we are talking about 1:30 now?

MR. TAVARES: Yes, probably.

COMMISSIONER BOYD: All right.

MR. TAVARES: We are going to continue and open the session for public comments. This will be on the record, so who needs to -- we have somebody from Transwestern, Paul --

MR. Y-BARBO: Y-Barbo.

MR. TAVARES: Why don't you identify yourself and make the comments?

MR. Y-BARBO: Good afternoon. I am Paul Y-Barbo with Transwestern Pipeline. I just want to give a very quick overview of Transwestern's system and mention that I will be making a more detailed presentation at the bi-annual workshop on natural gas issues on June 4th.

Transwestern is one of the largest interstate pipelines serving the California market. We regularly deliver up to 1,225 million cubic feet per day to Southern California via our interconnects with the SoCalGas System at Needles and the PG&E System at Topock. On March 1st of this year, Transwestern put our Phoenix lateral in service. We want to stress the point that we did not remove any delivery capability to California when we put the Phoenix lateral in service. Gas continues to flow to California at a fairly high rate. Currently, the Phoenix lateral is only utilizing about 200 million cubic feet per day of this delivery capacity, and we have unused capacity on the Transwestern system at this time, that could continue to serve California. With regards to some of Bill Wood's comments about concerns about peak, about there not being enough capacity into California during peak demand in winter and summer, Transwestern has a relevant amount of unsubscribed capacity that could be sourced from the San Juan Basin and serve California beginning in November of this year. For the first couple years, that is nearly 80 million cubic feet a day of unsubscribed capacity that someone could contract. It increases in the third winter period to about 110 million cubic feet per day, and after that it is 160 million cubic feet per day. So we consider that a nice sized capacity that could give California a little bit of cushion. Additionally, we are evaluating expanding our main line system from Thoreau going West. We have got numerous proposals that we are looking at in the range of 300 to 500 million cubic feet per day. Additionally, California customers should keep in touch with Transwestern because we have contracts upstream of California that come up for renewal from time to time, and those create opportunities for California shippers to subscribe to capacity on Transwestern, that could serve the California market. The Transwestern Pipeline connects to numerous supply basins, to the San Juan, the Permian, we have been flowing gas from the Mid-Continent Region on our panhandle lateral, and ultimately through our interconnects with our affiliate companies, we will be able to potentially access shale gas reserves, for example, the Barnett shale, and possibly even shale production in further East Texas. As I said before, I am planning to provide a more detailed overview of the Transwestern system at the June 4th workshop, and I will be prepared to answer questions that staff and other participants may have about Transwestern's role in supplying California's current and future natural gas requirements. Thank you for this opportunity to speak at today's workshop.

MR. TAVARES: Thank you, Paul. By the way, you mentioned the June 4th workshop. It is really the Natural Gas Working Group meetings that we have every six months, that we will have here at the Commission. We are still developing the agenda for that meeting and certainly we will give you an opportunity to make a presentation at that meeting. Anybody, anymore public comments or questions? Oh, please provide a business card to the Reporter. Yes? Rory?

MR. COX: Hi, Rory Cox, California Program Director at Pacific Environment. And I just wanted to give my reaction to the data presented on the lifecycle emissions of liquefied natural gas. The presenter, Mr. Kennedy, mentioned that there was disagreement within the studies done on the lifecycle emissions of LNG, and I have not found that to be the case. I know of three very rigorous studies that have looked at the lifecycle emissions of LNG from several different directions, and they all conclude generally the same thing, which is that importing LNG adds about 15-25 percent extra greenhouse gas emissions over natural gas that is produced domestically. The one outlier is the one that I have brought up earlier, which was the PACE (phonetic) Report, which is industry-funded, and that is the one that breaks the consensus, that would be the fourth one. But the other three, which are done by an academic university and Climate Mitigation Services has done another one, and then we have also produced one, which was done by Bill Powers, an engineer, basically have the same consensus. And, again, these were done independently of each other. But the other thing that I wanted to comment on is that the comparison of LNG and coal is really the wrong comparison in California because coal is, for the most part, off the table, and LNG will not displace coal. What LNG will displace is domestic natural gas, so really the debate that we should be having is how does LNG stack up to natural gas, how does it stack up to renewables, and how does it stack up to conservation. And I think it is pretty clear that, in any of those comparisons, LNG is by far the most intensive in terms of burning greenhouse gases, and it is not a trivial amount, even at the low case which would be 15 percent, we are talking for one LNG terminal, it would be, you know, at full capacity, about three million tons a year up to five million tons a year, so that is a significant increase in greenhouse gas emissions from importing liquefied natural gas. So I would be happy to produce any of those other reports that you have not looked at, if you would like. I can look them up pretty easily. So thanks a lot.

MR. TAVARES: Well, thank you very much. We certainly would like to see those studies. Later this afternoon, we will have also a presentation from South Coast Air Quality Districts, so we can go over a little bit more about those potential impacts. Any more questions? Anybody? Anybody out there? Go ahead. Apparently there are no more questions. So we will come back around 1:30 for more presentations. Thank you.

[Lunch Break.]

MS. KOROSEC: Take your seats, please.

MR. TAVARES: Let's start the second part of the workshop. Commissioner Boyd, are you ready?

COMMISSIONER BOYD: By all means.

MR. TAVARES: We are going to continue the presentations from outside experts. Next, we have Amy Mall, and she is going to be making a presentation through WebEx. She is with the Natural Resources Defense Council. Before joining NRDC, she served as an Advisor to the Director of the White House National Economic Council. She also has worked for Senator Diane Feinstein and for former New York Governor, Mario Cuomo. She holds a Masters Degree in Public Policy from Harvard University. Amy, you are next.

MS. HALL: Great. Thank you.

MR. TAVARES: Thank you.

MS. HALL: Well, thanks for inviting me and for including this issue on your agenda. We really appreciate it. I am, as you can see from the title page, it just says oil and gas production, and I will use those terms interchangeably because the impacts that we are concerned about may extend from either oil or gas production. So I know you guys are focused on natural gas. Also, a lot of the information that I have in here are from the Rocky Mountain Region. I know you are focused on the Marcellus, but in general, whether it is oil or gas, whether it is shale, or [inaudible], or [inaudible] formation, a lot of the potential [inaudible]. So if I use some of the terms interchangeably, I am talking about the impacts. And I just used the little down arrow and it did not make my blank change.

MS. KOROSEC: Amy, this is Suzanne. I will go ahead and run the slide for you. Just tell me when you want to change it.

MS. MALL: Okay, great. Unfortunately --

MS. KOROSEC: We are having a little bit of technical difficulty here, so bear with us.

MS. MALL: Maybe that is why it is not working on my end.

MS. KOROSEC: That may be, yeah. Okay, it is working from here now. So just go ahead and let me know when you want me to switch the slides.

MS. MALL: Okay, great. So we are concerned because, you know, you have heard that there is a lot of potential for future natural gas production, and a lot of it is in unconventional, but industry is present in 34 states and that includes states from California, too, New York, Pennsylvania, etc. And there has been a lot of growth just over the last 20 years, but we expect hundreds of thousands of new wells if just all the potential that is expected is implemented.

There are different environmental impacts we are concerned about, there are a lot of impacts directly in communities, and human health impacts, as well, and some of the wildlife impacts that I am going to talk about also.

[Inaudible WebEx]

COMMISSIONER BOYD: Thank you, Amy. This is Commissioner Boyd. We will see if anybody has any questions. First, let me just say that we appreciate the nod to California, at least in one area. But I was sitting here thinking, my goodness, what a failure of even enforcement of, or a total lack of rules and regulations, I guess, in some parts of the country, either enforcement of federal or lack, or state or local, or a lack of state or local regulations. And the only other observation I will make as a long-time veteran of all of this is, many of the problems we have created for ourselves such as your reference to the Baldwin Hills, and maybe California is done a better job at mucking things up because of Prop. 13 a long time ago, but it used to be industry was out there by itself, and not many people lived around it. But in California, they have zoned every square inch of land there is for people to live and work, and so -- and they have gone right up to the fence lines or on into a lot of this commercial territory. So, as you say, in certain areas we have now very significant problems because I think local officials paid no attention to the environmental issues, even though California has got some of the most active air and water and public health regulations around, even California does have some problems. So it is valuable to point that out. But it does look like the playing field is not too level in some parts of the country. So I appreciate what you have to say.

MS. HALL: Yeah, well, you raise a lot of the important points.

MR. BRATHWAITE: Amy, my name is Leon Brathwaite. I work here at the Energy Commission. Can you hear me?

MS. HALL: Yes.

MR. BRATHWAITE: Okay, good. I just want to ask a question about potential contamination of groundwater. Now, groundwater normally occurs usually at depths of less than a thousand feet, and the shale formations and maybe nearly all natural gas formations are usually at depths greater than 5,000 feet. So where do you see is the danger in the groundwater becoming contaminated in the process of, say, hydraulic fracturing or any of those operations that we do in the oil and gas industry?

MS. HALL: [Inaudible]

MR. TAVARES: Next, we have two speakers from Sempra, Scott Wilder and Kevin Shea. Scott is a SoCalGas Business and Economic Advisor, and Kevin is a Product Manager for SoCalGas. Kevin?

MR. WILDER: We would like to thank Commissioner Boyd and the entire staff for letting us come here and share some of our thoughts and centrist thoughts about these three issues in the natural gas industry here. Before Kevin speaks to address LNG and infrastructure, I will just speak briefly to some of the shale oil, shale gas issues that have been actually much much more expertly covered, I think, in our three excellent speakers this morning. We are taking directly some of the Commission's questions in the meeting notice here. Well, as we have heard this morning, there is huge shale gas resource base in North America, both U.S. and Canada, the largest currently being Barnett, but Haynesville not far behind, and Marcellus just starting out, but eventually which may pass up even Haynesville. Also up in Canada in Northern Alberta and Northern British Columbia. Just to hit some of the highlights here, are the current shale reserve estimates reliable? Could they be improved? And how? Well, the reserve estimates, it depends on technology and it depends on price, on economics. So in a sense, the estimates are as reliable as the gas price forecasts are. In terms of long-term gas price forecast, I think we have seen even over the last couple years how quickly things can change. And so we, at best, I think, can take ranges of what we have seen historically and ranges of what we may see in the future. And then on the bottom of the slide here, the current decline in the gas prices, I think it was mentioned this morning by at least a couple of the speakers that the vertical drilling has declined drastically, but the horizontal drilling, which is predominantly what is in the shale gas business, really has not gone down much. In fact, in the big fields, it has stayed fairly steady and we would not be surprised at all, even if gas prices remain at the current level to see horizontal rigs and drilling in places like Haynesville and particularly Marcellus where it is just beginning to actually pick up.

The water question is a big one. It has been mentioned about the issue of treatment and disposition after the fracturing and the use of the water, but particularly out West there are shale reserves in places like Wyoming and Northwestern Colorado and Eastern Utah, where because of the aridity of the water availability or lack thereof, is probably going to be the main constraint on any shale development. Also, interestingly, in Canada, you would think of Western and Northern Canada as being a water rich place, and it is. But a lot of the potential shale areas in Northern parts of Alberta and British Columbia, the easiest season to develop some of these very remote areas, just in terms of transportation, is in the winter time, and there is a lot of water, but it is frozen. So liquid water is a real issue in quite a bit of the Northern Canada area for potential shale development.

The last area down here, we have looked at a study done by the Ziff Energy Group from Canada, and as has been mentioned this morning, I do not want to repeat what our three excellent speakers this morning have gone over in detail, but just the combination of the technological breakthrough of combining horizontal drilling with the hydraulic fracturing is really what has changed the picture over the past few years and brought shale from relative obscurity, even three or four years ago, into what is probably the prime spotlight in the gas industry right now. This has been a very popular map today. I think I am probably the fourth person to show this and it probably demonstrates the usefulness of this map, if anything else. A couple points here. You can see the vast bulk of the shale is in the South and East parts of the U.S. And this map, in particular, shows that we have mentioned and heard about the geographical size, particularly, of Marcellus. And this shows it really clearly. This does not even show the Canadian areas, but one important point is that the Canadian potential, if anything, is even larger than the U.S. We have seen studies showing 500 to 1,000 Tcf here in the U.S. for potential, and I think Gordon mentioned Navigant's study at 842 or so. But Canada potentially, if it is developable and if the water issue is resolvable, maybe at the high end of that.

Finally, the pipeline issues -- I know this is a lot of information for one slide here, but basically the point is here we have got a tremendous amount of pipeline construction either underway or being planned. The bottom left corner there, the 33.43 BCF/D Total that is the aggregate of what is shown on this chart, that compares to a current total, according to the EIA, of around 170 BCF/D capacity in the U.S., you know, in that roughly 4,000 miles projected here in total would be added to about what is roughly 220,000 miles right now. So with that, I am going to turn it over to Kevin to address LNG and infrastructure issues.

MR. SHEA: Thank you. My name is Kevin Shea. I have been involved in the LNG issues, specifically gas quality, since LNG became a hot topic in California. At that time, the Pacific Basin was long on LNG supplies, more has shifted dramatically since that time. This was covered pretty well by Robert Kennedy earlier, but one of the key issues in the LNG trade is there is a lack of transparency in the world markets. We really do not know what is coming on line, when it is coming on line, where the gas is going, and what prices are. So it is difficult for anybody to just pull out their crystal ball and say, you know, what is coming to the U.S.? And we see in a lot of reports what is coming to the U.S., but the question becomes, at least for us in California, is what comes to California. Are we going to be able to draw supplies away from Asia for California? You know, if it was just price-based driving the LNG trade to North America, we would not see a whole lot coming to the West Coast. But there are other factors that drive trade in the LNG markets. I am going to cover a lot of this stuff at a higher level. We have put a lot of detail into the package, but I am sure everybody can read the detail.

On the next page, our question asks, are exporting countries going to develop into an energy cartel? Well, we have all seen this slide numerous times about the shale in North America. It would be nice to have the shale around the world. There are large deposits of shale everywhere, Australia, China, we just mentioned that Canada has it. You know, we really probably do not foresee a cartel. In addition, you have got the OPEC states that have the LNG, Russia with the LNG, but what people do not talk about that much is all the Australian supplies. They have talked about it for years coming on line, we have not seen great volumes there yet either. Will shale displace LNG? I think when you look at North American markets on terminals and markets on LNG, each location has specific issues. You start in the Northeast coast with the Everett Terminal. They bring in gas during the winter to meet the winter peaking demands, pipeline constraints, and issues like that. You move your way down and Cove Point and Maryland has different issues on why gas lands there and not -- and then you go down to the Terminal in South Carolina, in the Georgia-South Carolina area, Elba Island, different set of issues on what draws gas there and what does not. Then you swing down to the historic, the terminal that has been a long time down in the Gulf Coast, which has basically been an economic terminal if you look at supplies over the years, they run at very low capacity. People believe the LNG was going to come in to the U.S., you look at the Gulf Coast and there is a lot of terminals that are operational or that are coming on line. West Coast, as I said earlier, we saw a lot of interest five years ago, California is a big market, only one terminal got built. There is a couple terminals still looking at the California market, there is the Oregon terminal, and then you go up to Canada and they have put in a petition to be able to export gas from the Kitimat LNG Terminal facility. As Dr. Terry Engelder indicated, the big game changer has been the shale. The number is just incredible. We started seeing that, as he mentioned, 6 months, a year and a half ago, two years ago. It has been a huge game changer. The West Coast Terminal, the Ecca (phonetic) Terminal has been -- they did start-up testing last May, a year ago, we were in the field doing monitoring, we have not seen other gas come from that terminal even though it has been commercially operational for a year, we have not seen any molecules come into California since that initial start-up period.

Life Cycle has been talked about here. I have done some work in the first two columns, have done some analysis and understand those numbers. When you get to the life cycle, a lot of it, as you compare these numbers, is your assumptions, especially in the areas of the transmission storage, what happens in the fields, how it is produced, you heard the previous speaker talk about gas being vented in foreign fields where you are producing oil, gas gets vented, if we can capture that. So it all depends on your assumptions, the fields it is coming to, on how you grind your numbers. Also a comment this morning was on comparing the LNG to coal. When we are looking at a transition in California to reduce our greenhouse gas footprint, you look at how much or our electricity comes from coal fire generation. And natural gas and LNG can provide a bridge or a transition period as you move away from the higher greenhouse gas issues with coal fire generation, as we get into more renewals, solar, things like that. So we believe it is a pertinent comparison for California.

Pipelines and infrastructure, that was covered this morning and also by Bill Wood. We are of the belief that California has the appropriate amount of infrastructure in place today to cover most of the issues that he identified and we will be providing comments back to him. One thing I would like to say is his report, really interesting. I think it is a great exercise for California to be doing, an important exercise, but to have it rolled out in public before there can be some comments on it, and some double-checking of the numbers and some of the assumptions in the way information is presented, we really would like to have an opportunity to try and have some feedback on that before it is presented publicly. There are questions on peak demand. Here in California, as has been mentioned, we see moderating peak demand in the winter because of our energy efficiency, summer peak demand questions as we bring on more renewable resources, solar and wind. We expect to see more volatility. As the wind does not blow and it gets hot, we are going to have to have peakers (phonetic) ramped up real quickly. California will have to be able to substitute natural gas fire generation in short order when renewables cannot deliver for us.

Additional infrastructure -- SoCalGas is in the process right now, we will be filing this summer for expanding our storage. It was decided in the recent BCAP, we are going to be putting in 7 Bcf of inventory -- I believe it is 145 million a day of firm injection. We have also got Northern California, and maybe PG&E will talk more to it, Gil Ranch Storage facility is going through its Certificate of Public Convenience, and then just this last week, Wild Goose announced their Phase 3 expansion of their storage facility. As we talk about infrastructure, and I think that Bill brought it out, questions of supply, we can have plenty of storage capacity here, but if parties are not using it to store gas, and gas is not available in storage, we can have a ton of infrastructure in storage, but if the gas is not there, we play catch-up during the type of 2000-2001 period. So one of the things that we will look at is
-- one of the monitors we will want to keep an eye on is what kind of gas is in storage year on year. When you get

to low storage, you start seeing low, Hydra in the Pacific Northwest, you know, there are indicators that can come out of a study like this, because these are the types of things we may want to be watching going forward, so we can try to avoid those types of situations. Another key piece that I do not think was hit on that much in the report, and that is having an LNG Terminal on the West Coast capable of serving California markets. Basically, you have got a 1 Bcf capacity there that it is not going to set the price, but it will moderate prices; as California prices go up as they did in 2000-2001, we will be able to track supply and it will help reduce cost. So 1 Bcf a day is a significant amount of gas for California. So it should be able to have a major moderating effect on prices.

There was talk about the infrastructure, pipelines to California. We are in agreement with the gentleman, from Mojave. We have looked at the same analysis that he talked about. Yeah, as pipelines go down to serve other markets, that does not necessarily take away capacity for California. But those are key issues that we need to look at and we need to discuss because we really do not want to be cut short longer term.

I covered the storage. Could shale supply displace Rockies and Southwest gas? I think if you go back to Terry's presentation, what you see is, it actually -- shale gas can actually push more Rockies, more Southwest production, towards California, as the Barnett and Marcellus take markets and pipeline capacity to feed Midwestern and Eastern markets.

I think this has been talked about, or will be talked about, there is a number of expansion projects on here. We put it as proposed construction because not all of it gets built. Currently, I think Ruby is the only approved project. Transwestern did talk about their expansion down to the Phoenix area.

This is a slide of upstream capacity, pipeline capacity available to California. We believe that currently this is adequate and will meet the peak demand requirements of the state. This is a summary SoCalGas currently has in place and also the identification that we are adding 7 billion cubic feet of inventory, and 145 billion cubic feet of injection. There are two important figures because, the more injection you have, you can fill your inventory, your storage fields, when gas is not in demand. It allows you to do the catch-up so that when the peaks come during the week, when the electric generation is on, when people are heating their houses, you have the gas and storage to pull out to make it. Again, we believe that it is more than adequate to meet it. And, again, Bill Wood's study, we think is a great exercise and we would encourage to have at least one round of review before these things get released publicly. We do not want to create unnecessary, undue concern for people. We will be making comments on that report in the next 20 days. As anything, for anybody that does this kind of work, numbers are hard to get, keeping accurate numbers, what is up to date, is hard to get. So we will be updating some of the numbers that Bill has in his presentation.

COMMISSIONER BOYD: Thank you. Questions from the audience? Yes, sir.

MR. LAETZ: Good afternoon, Mr. Shea. My name is Hans Laetz. I am a journalist. I work for the California LNG News Service. I have got a couple or three for you. Is the 2.5 billion cubic foot expansion that was the subject of the open season at Costa Azul, is that still in the works? Or has that disappeared?

MR. SHEA: I cannot answer that. I work for SoCalGas and they are an arm's length from our affiliate. Sempra answers that.

MR. LAETZ: Okay. Currently before the Public Utilities Commission is a request for something called "Off-Site Delivery," where Southern California Gas and San Diego Gas and Electric are, as I understand it, asking for permission to use their infrastructure to deliver gas from the interstate pipeline where it arrives at Otay Mesa, to other customers, non-PG&E. Can you explain who those other customers are and how much gas we are talking about, that will be coming in from overseas and being shipped through the Southern California system to other customers?

MR. SHEA: First off, I am not involved in that proceeding, second is we really do not do any forecasts on what is coming in at Costa Azul. It is impossible to forecast it.

MR. LAETZ: But it is using your network, though. It will be going through your pipes.

MR. SHEA: Well, most gas would come in and move by displacement. If we brought a VCF into our system, it is not going to get to Phoenix, it will displace gas that is coming from the north or from the east.

MR. LAETZ: I see. Final question for you. The injection project you are proposing as part of the BCP settlement, where will that be? And how will that relate to existing injection storage projects you already have at Playa Vista and Long Beach, I think?

MR. SHEA: The project will be at Aliso Canyon, which is in the top of the San Fernando Valley. It will not have anything to do -- the 7 Bcf of inventories at Ono Rancho (phonetic), and the injection is at Aliso Canyon and we will be filing CPCN, Certificate of Public Necessity and Convenience this summer on both of those. But neither of them are associated with the PDR storage facility.

MR. LAETZ: Thank you very much.

COMMISSIONER BOYD: Thank you very much.

MR. TAVARES: Kevin and Scott, thank you very much. Next, we have Martin Kay from the South Coast Air Quality Management District. He is currently Program Supervisor for the South Coast and has worked for the District for 34 years. Martin?

MR. KAY: Good afternoon and thank you for inviting me. South Coast Air Quality Management District is home to nearly 40 percent of Californians, L.A., Riverside, San Bernardino, and Orange Counties. And our district is responsible for controlling the emissions primarily from stationary sources, as well as planning for how we will attain the federal and state ambient air quality standards. The 100 percent line here is the federal standard for the various pollutants. This shows that we have made a lot of progress over the years in reducing emissions. The ARB just released an almanac of air quality just this week, that shows a lot of this information. We have attained the CO standard and the NO2 standard, these two lines below the 100 percent level, but we still have problems with ozone and PM2.5, we are significantly over those standards.

Our last Air Quality Management Plan in 2007 identified that NOx, as in Nitrogen, are probably the most contaminant that we have to reduce. This upper blue line shows the Nox emission reductions that we would expect to occur in 2014, when we have to meet the PM2.5 standard, and in 2023 when we have to meet the Ozone standard. Significant reductions in NOx are forecast without any new rules, but in order to achieve these stringent standards, this yellow line down here shows where we need to be to meet those standards, so we have to reduce it for about 500 tons per day to about 100 tons per day of total NOx emissions. This is going to be a very difficult job.

AQMD loves natural gas. When I started with the district 34 years ago, the electric utilities still used a lot of fuel oil to produce electric power. Their emissions were about 150 tons per day of Nox. More recently, they burned completely 100 percent natural gas, and their emissions are about 2 tons per day of oxygenized and nitrogen, and because of better emission controls, as well -- 150 tons to 2 tons -- that is pretty good. This shows the supplies of gas to California, a small amount of in-state production, most of it from Canada, the Rockies, and the Southwest.

We do have some new players, Bob talked about the shale oil. We are glad to hear there is going to be a plentiful supply of natural gas. That is good news. But another significant player may be these proposed LNG terminals, about 10 terminals are proposed or installed on the West Coast of North America, one is actually installed here down in Mexico, and I will be talking about that a little bit more.

There are three terminals that could provide gas to Southern California and one potential expansion at the Costa Azul facility. Altogether, these could provide up to a 4.8 billion cubic feet per day. Since Southern California gas usage is about 2.5 billion cubic feet a day, that is enough provide almost twice as much gas as what is used in Southern California, so that is a lot of capacity there. That could totally change where we get our gas from.

An important item with natural gas quality is something called the Wobbe Index, or Wobbe Number; basically, it is the higher heating value in BTUs per cubic foot, which everybody has heard of that, pretty much. But it is divided by the square root of the specific gravity. The Wobbe Index is a better indicator of gas quality. As the Wobbe Index increases, the heat input rate tends to increase through burners and, for most burners, when that increase happens, the air flow does not increase along with it, so as a result the air to fuel ratio decreases. And when you get changes in air-fuel ratio, you can have changes in emissions. Exceptions are equipment that has some kind of closed-loop air-fuel ratio control and oxygen sensors, like some stationary engines. This shows what the natural gas is today as a system average for SoCalGas, basically a Wobbe Index is about 1332 Btu per standard cubic foot. Higher heating value is 1020 Btu. The important factor here is, generally, it is a very high level of methane, about 95 percent, about two percent of total inerts. The inerts actually cause the Wobbe Index to be lower than they would without them. And then very low levels of Ethane and Propane, or C3+ which are also VOCs. The potential LNGs tend to have much higher Wobbe Index, 1373 to 1446, they tend to have no inerts in them, they boil off, and much lower Methane levels, 83-91 percent, higher levels of Ethane, up to 13 percent Ethane, up to five percent Propane, and this causes the Wobbe Index to be much higher.

There have been quite a few natural gas studies, interchangeability studies. In 2005, the Natural Gas Council published a White Paper on Natural Gas Interchangeability and there is a lot of good information there about what happens when you change one gas for another. And they recommended some criteria for what is interchangeable in a safe manner. There is a link there to that study. Southern California Gas Company has also been very active in this area and has done some testing, had some workshops, some meetings. And I will be showing a little bit some results of that. The California Energy Commission has two projects going right now where there should be some results to show soon, Lawrence Berkeley National Laboratory is doing a lot of testing of residential appliances, the Gas Technology Institute is testing industrial burners. Last year, when the LNG was actually delivered to the San Diego area from the Mexican terminal, San Diego APCD, and San Diego Gas and Electric, and SoCalGas staff were down there doing some testing, as well. Different combustion equipment behave a lot differently, depending on the type of burner it has, the type of controls it has. The good news is some equipment is very tolerant to changes in gas quality and basically it does not have hardly any change at all in emissions. Most of the big power plants are that way, as well, because they have good controls and they monitor air field ratio. But there are some equipment that are small, that do not get monitored, that are affected by natural gas quality, and this shows some of the sensitive equipment that had emission increases as the Wobbe Index increased. And most of the time it is fairly linear. As the Wobbe Index goes up, the Nox goes up along with it. Here is the type of equipment that was tested that were sensitive. Energia Costa Azul Energy Terminal in Mexico, it is located 14 miles north of Ensenada and 55 miles south of San Diego, it is the first West Coast LNG receipt facility, about 1 bcf per day of capacity. It was commissioned with the first cargo in May of 2008. It is built by Sempra Energy and Sempra has 50 percent of the capacity. They have leased the other 50 percent to Shell. And Shell has, just in the last month, announced that they have sold some of that capacity to Gazprom, which is the Russian gas supplier. The gas -- this terminal is supposed to be coming from Tanghuh, Indonesia, and Sakhalin, Russia, these projects are just gearing up right now, they have not come on full flow yet, so right now if there is anything coming in, it is probably going to be a spot cargo. Right? There are no significant flows into the U.S. at this time.

Okay, this shows the southern part of the SoCalGas and San Diego gas system. Right now gas comes in the Blythe-Ehrenberg area from the El Paso pipeline, starts flowing west, and then that gas flows down into Imperial County into Los Angeles Area, and South into San Diego. Also, there is some gas that goes south on the North Baja Pipeline there, that green pipeline here, and flows into Mexico, by Baja, California.

When supplies of LNG start being delivered on a regular basis, the flow of the North Baja pipeline may be reversed, and that capability is already there, or it will be reversed and delivered to the Blythe- Ehrenberg area. Also, Otay Mesa is an important receipt point to supply the San Diego area. If this happens here, San Diego will probably be on 100 percent LNG. And actually there is some possibility of LNG derived natural gas flowing north into the SoCal district, at this area here.

SoCalGas is required by California Public Utilities Commission to monitor and manage the heating value, not the Wobbe Index, of natural gas, and they have set up these BTU districts that are shown in our area. Some of them are very large, like Riverside, this very large area here, some are quite small. Usually there is some local production in these areas, which is why they have a separate PT District. Over the 2000, 2004 time period, for which we have some data, the Wobbe Index fluctuated between these levels. Remember I said before it was about 1330 average, it is only about a plus or minus one percent, at most, change of Wobbe Index over that five-year period, so it really did not change very much. With the LNG that came in, in May of last year, it was about 1380, right about here. And as a result of CPUC decision, which required SoCalGas enroll 30 to limit Wobbe Index increases to 1385, so this is significantly higher than what we are used to seeing. And this 1385 limit is four percent higher than the system-wide average, which is what the NGC White Paper recommended, no more than four percent increase in Wobbe Index in order for equipment to be safe.

What is going to happen to the Wobbe Index in AQMD? Well, it is going to depend on how much LNG is delivered, and we do not know how much of that is going to come to the ECA Terminal. Some of those cargos can be diverted to foreign markets, some of it will be used in Baja, California, and in San Diego, what is leftover could come to AQMD. There really are not very good public data, publicly available data, to tell us what changes are happening to our gas quality. So as a result, AQMD has proposed a Rule 433 Natural Gas Quality, and the purpose of it will be to monitor the quality of natural gas supplied to users in AQMD, and to monitor and mitigate any effects of natural gas changes on combustion equipment and AQMD. It does not place any limits on the quality, or does not set up any specifications for natural gas quality.

The elements of the proposed rule include historical Wobbe Index data to fill the gaps since 2004, establish baselines, current baselines, before LNG arrives, also it requires SoCalGas to implement a Gas Quality Monitoring Plan that will monitor Wobbe Index in these BTU districts, as well as the higher heating value. SoCalGas has had an LNG Rollout Plan in effect in San Diego, and they have plans to do it in SoCal, in our area, as well. So we are not actually making them do this, but we are putting it in the rule to make it a more formalized process, so that we can participate in this LNG Rollout Plan. It also has an element in there to calculate an annual estimate of what the emission impacts are from any changes in gas quality, and this rule is going for adoption to our Board on June 5th, next month. Thank you.

COMMISSIONER BOYD: Thank you, Martin. Anybody have questions for South Coast, for Martin? Seeing none, I thank you, Martin.

MR. TAVARES: Thank you, Martin. Next, we have Richard Myers from the California Public Utilities Commission. He is a Supervisor of the Natural Gas Unit, the Energy Division of the California Public Utilities Commission. He has held this position for almost 10 years and he has been with the CPUC since 1978. So, Richard, you do not look that old.

MR. MYERS: Good afternoon everyone. I just wanted to -- this is probably no surprise to everyone, but I just wanted to restate that the PUC jurisdiction over the California infrastructure is very extensive. We regulate the natural gas utilities in the state, of course, but they only deliver about 80 percent of the gas consumed in the state, and their infrastructure, along with that of the independent storage providers in the state is regulated by the PUC, so that is quite extensive, as shown on this page. And the PUC can have a direct impact on the amount of natural gas infrastructure capacity available in California, but we do not have jurisdiction over all of the infrastructure in the state. We do not regulate interstate pipeline systems that come into the state, or the ones that deliver into the state from out of state, and we do not regulate California production. We do not have jurisdiction over LNG terminals either. But the CPUC, while we cannot directly determine whether interstate pipelines get built, or whether LNG terminals are constructed, or whether new supply sources are produced, we would like to think that we can have some influences on decisions by those developers to move forward with such projects.

I would like to think that the CPUC policies on gas infrastructure are basically pretty simple, as laid out on this page. For core procurement customers, we want to make sure that utilities have diverse reliable sources of supplies and that core customers will be served, even under quite adverse conditions. This requires utilities to have reasonable interstate pipeline capacity rights, access to sufficient storage capacity, access to a variety of supply sources, and enough infrastructure, such that core customers will be served, even under quite severe conditions. For example, I believe that PG&E designs its system such that core demand will be met, even on the coldest day in 90 years. For overall infrastructure, CPUC policy is basically to assure that all deliveries are made with a high degree of certainty, constraint points are undesirable, consumers should have access to a variety of supply sources. We encourage new storage capacity because of its desirable economic and reliability attributes, and we want to provide fair access to the utility system for new pipelines and suppliers.

Although it can do so, the CPUC usually does not directly order that new infrastructure capacity is constructed. Rather, the CPUC usually either requires the utilities to adhere to certain reliability standards of delivery, or allows market participants to determine whether infrastructure is constructed. In some cases, when market forces are the determining factor, the requesting parties may need to pay for the infrastructure upgrades themselves rather than the utilities. As this slide shows, there are a variety of means by which the CPUC encourages or requires new infrastructure. For example, we have market mechanisms when a independent storage provider wants to construct a facility, they basically need to obtain market support for that facility themselves, and they in turn take the risk for the construction of that facility, and in turn the PUC often provides, or typically provides the storage facility, or allows the facility to charge market-based rates, as long as there is not a showing of market power by that facility. And there are other different ways as laid out on the slide that PUC either encourages or requires new infrastructure in the state. Before the PUC right now, there are a number of pending proceedings involving new infrastructure, and there have also been a number of recent actions that the PUC has taken to either encourage or require new infrastructure, or require utilities or allow utilities to obtain interstate pipeline or storage capacity rights for the customers that they serve such as core customers. For example, the PUC recently approved PG&E contracts for interstate pipeline capacity rights on the proposed Ruby Pipeline. Last year, the PUC approved Lodi Gas Storage's Kirby Hills capacity expansion. There is before the PUC now another PG&E Request for Offers (RFO) for incremental core storage capacity. In the SoCalGas Accord proceeding that was approved in 2007, I believe, there were a number of local transmission projects that were proposed in that proceeding, and it is my understanding that PG&E is proceeding to construct those local transmission projects. As Kevin Shea mentioned, the PUC recently approved a settlement in the BCAP proceeding for SoCalGas that will result in SoCalGas expanding their storage facilities. Before the PUC now, there is a pending Gill Ranch and PG&E Storage Facility, and also a Sacramento Natural Gas Storage proposal for a new storage facility. Just within the last few weeks, Wild Goose Storage also proposed yet another capacity expansion at their facility, and also I will be discussing the Interstate pipeline consultation process at the PUC for core procurement interstate capacity rights. So as I mentioned, actually, in November of 2008, the PUC approved PG&E contracts with the proposed Ruby pipeline for long-term firm interstate pipeline capacity rights. And these capacity rights were for both the Core Procurement Department and the Electric Generation Department of PG&E. This will for the first time, if the Ruby Pipeline is constructed, will allow for the first time PG&E to gain very significant access to Rockies supplies, and we believe that the Ruby Pipeline will be beneficial not just for PG&E, but for other Northern California consumers, as well. And right now, we are expecting a 2011 operation date for that pipeline.

Early last year, Lodi Gas Storage requested approval of a second phase of its Kirby Hills Storage Facility Expansion and the PUC did authorize that increase in working storage capacity by 6.5 Bcf and an increase injection and withdrawal capacity by 200 MMcfd.

A couple years ago, PG&E proposed that they be allowed to obtain incremental core storage capacity for their core customers, and they have proposed a process under which they could obtain that incremental storage capacity. And this is for storage capacity beyond the capacity that has already been authorized for customers at PG&E's storage facilities. PG&E proposed this process so that they could increase the reliability of delivery to core customers. So the PUC did, in fact, approve that process under which the Core Procurement Department or PG&E could obtain incremental storage capacity, and the PG&E Core Procurement Department has issued two RFOs, one in 2007 and recently in the end of 2008, for a two-year term contracts, and it turned out to be both with PG&E's own storage department and with Lodi Gas Storage. And just a few weeks ago, PG&E filed a new request with the PUC to issue another request for offers for new incremental storage capacity, to replace some of their seasonal Baja capacity for core customers. But that latter request is pending before the PUC.

As I mentioned, in September 2007, the PUC approved the latest gas accord settlement, and I will just mention the gas accord is simply a proceeding under which the PUC addresses various issues and rates dealing with PG&E's backbone and storage facilities. The gas accord goes back to the original settlement of a number of parties in, I think, 1997, where there was a major settlement, thus termed gas "accord", and it has held that term every since. But pursuant to the latest gas accord settlement that was approved in September 2007, PG&E proposed that they be authorized to embark on a number local transmission projects that were going to be constructed in the Sacramento and Fresno areas, and these areas had experienced some constraints in the past, so I was glad at least to see that PG&E got approval for those projects. It is my understanding that PG&E is, in fact, going forward with different phases of those projects on their local transmission system.

I was also glad to see that, finally, in Southern California, we are also beginning to see some additional storage capacity expansion. In the first phase of the SoCalGas and SDG&E biannual cost allocation proceeding, a settlement was approved by the Commission in which SoCalGas would expand its storage inventory capacity by 7 Bcf, and its injection capacity, I believe Sol Canyon, by 145 MMcfd, and this was expected to be happening over a five or six-year period, 2009 to 2014, and it is my understanding that SoCalGas will be filing applications soon at the Commission for authority to proceed with those storage expansions. I will just mention that, also in Phase 1 of the BCAP, the core customers of SoCalGas and SDG were also allocated a very healthy 79 Bcf of storage capacity.

Pending before the PUC is also the Gill Ranch and PG&E Storage Project near Fresno. They filed that application with the PUC in July of 2008. Gill Ranch is to own 75 percent of that facility and PG&E is going to own 25 percent of the facility. It is my understanding that they will separately market the capacity for that facility, it will not be technically a jointly owned project. They will actually separately mark it their own capacity to customers. The first phase of the facility has 20 Bcf of inventory capacity, that is my understanding, it also has the potential for an additional 20-25 Bcf of additional inventory capacity. At the PUC, the applicants have indicated that virtually all of the non-CEQA related issues have been settled, so now we just have to wait for the environmental report on the facility and I am hoping for a final decision before the end of the year. Sacramento Natural Gas Storage has also applied before the PUC for a new storage facility in the Sacramento area, with 7.5 Bcf of storage inventory, but this project has been opposed by a neighborhood group, I believe they are called the Avondale Glen Elder Neighborhood Association. And I think the neighborhood group is primarily concerned about safety-related issues. A few weeks ago, a Draft Environmental Impact Report was issued by the consultant, working for the PUC, and it stated that the facility was not the environmentally superior alternative. That is, the no-project alternative was viewed as the environmentally superior alternative. And the consultant also suggested that other locations, other than the proposed location, would be environmentally superior. And this was based primarily on safety considerations. So it is my understanding that the comments on the Draft EIR are going to be coming in a couple of months, and then the consultant will have to decide how it wants to change its Environmental Impact Report for the final report.

I think it was back maybe six or seven years ago that the PUC actually approved a Wild Goose Storage Expansion, but Wild Goose ran into some problems with a landowner association and it needed to condemn a small portion of property in order to deal with a pipeline related to this storage facility. And just recently in November 2008, the PUC did condemn that small parcel of land, so now Wild Goose Storage will be able to expand their facility up to 29 Bcf from the current 24 Bcf. And then just within the last few weeks, Wild Goose filed another application at the PUC for yet another expansion of their capacity and the proposal is to increase inventory capacity from 29 to 50 Bcf, and with also a corresponding injection and withdrawal capacity increases. Wild Goose estimates that the project could be completed in about two years or slightly less than two years.

Finally, I just wanted to explain a little bit about how interstate pipeline capacity for core customers gets approved at the PUC. Prior to 2004, the major utilities in the state mainly held a very small number of very long-term interstate pipeline capacity contracts. But in 2004, the PUC approved a streamlined process under which gas utilities could develop a portfolio of interstate pipeline capacity rights for core customers. The utilities must maintain a minimum level of interstate pipeline capacity rights that is roughly around their average annual core demand for each gas utility. And so this process involves a consultation process with the PUC's Division of Ratepayer Advocates, a consumer group called The Utility Reform Network, and the PUC's Energy Division. And basically, if the DRA in turn concurs with the utility proposal, the utility may request approval of the contract from the Energy Division staff directly, rather than going to the Commission for approval of the contract. And I think both the utilities and the staff have viewed this streamlined process as being somewhat successful. It has resulted in a portfolio of contracts for interstate pipeline capacity rights that is more diverse, involves a number of different terms of contracts, and in some cases, it has resulted in discounted rates from the maximum terror freight of the interstate pipeline. And in addition, it has resulted in a lot of staff and commission savings, rather than having each contract approved by a commission decision or resolution. I just want to end by saying there was a number of other recent utility expansions and measures preceding by the utilities either directly or indirectly related from PUC decisions. Back in 2002, the Commission determined that the open seasons should be held in certain areas of the SoCalGas or SDG&E system where there was constrained area on their local transmission system. And the utilities in Southern California have held open seasons and, as a result of an open season, they held some time ago the Imperial Valley local transmission capacity is being improved and that project should be completed this summer. The upgrades in the Otay Mesa area were completed in May of 2008, and it is my understanding that basically the LNG developers paid for the cost of those upgrades. Those upgrades will allow the LNG supplies to flow in through the Otay Mesa area at about 400 MMcfd.

And finally, the so-called Firm Access Rights Framework was finally implemented in Southern California in October 2008. This came out of a decision approving the FAR framework issued in late 2006, and hopefully this framework will help the market determine where receipt point capacity into the SoCalGas and SDG&E system is most highly valued because the market basically obtains firm capacity rights and pays for them at different receipt points into the Southern California system. So hopefully that will give people a better picture of where the highest demand for receipt points rights is desired. And also, the FAR framework will assure LNG suppliers that they can gain firm access to the Southern California transmission systems. So that is all I had for today. I am glad to take any questions.

COMMISSIONER BOYD: Thank you, Richard. Any questions for Richard? You nailed it.

MR. TAVARES: Thank you, Richard. Yes, I was with the PUC, and it was a long time ago -- in 1982 to 1984. Next, we have Tom Price. He is with El Paso Natural Gas. He is the Vice President of Marketing and Business Development for El Paso Corporation and he will be talking about Ruby. Tom?

MR. PRICE: Thank you, Ruben. Thank you, Commissioner Boyd and Ms. Brown. I appreciate the opportunity to be here this afternoon and update the Energy Commission and the audience on our Ruby Pipeline Project. I will be making in my presentation some forward-looking statements, so I have our standard cautionary statement that you can read on your leisure.

As way of background, I thought I ought to take a minute and explain where Ruby is originating from, from a corporate perspective. Ruby is a proposed project that is coming out of the El Paso Western Pipeline Group, which is part of the El Paso Pipeline total system group. Shown here on this map is the infrastructure owned by El Paso Corp. It is the largest transporter of natural gas in North America. We move about 30 percent of the gas that is consumed in the lower 48 and have about 20 percent of the U.S. Interstate Pipeline mileage. The pipelines that I work are on the western half of the United States and basically are shown here, Colorado Interstate Gas, Wyoming Interstate, Cheyenne Plains, El Paso Natural Gas, and they also have some Mexico Ventures. But this gives you an idea of our footprint.

But what I am here today for is to give you some specifics about our Ruby Pipeline Project. Ruby is a $3 billion pipeline that will run from Opal Hub to Malin Hub in Southern Oregon. It is 680 miles of 42-inch pipeline, its initial sizing will be between 1.3 to 1.5 Bcf a day, it could be later expanded by compression addition up to 2,000 or 2 Bcf a day. It will be a high pressure line with an MAOP of 1,440. The initial design anticipates about 140,000 horsepower of compression. It will have eight interconnects initially, four on the receipt side, and four on the delivery side, which include Paiute in Nevada, Tuscarora, PG&E, and GTN in Oregon. It has been an interesting time in the Rockies over the last couple of years. This kind of is a picture of all the competing proposals that were out there in the marketplace last summer. It was a very hectic time in the marketplace, as market participants were sorting through which projects to back and move forward with. At this point, the only projects out of this maze that have gotten the critical mass of contractual support to move forward are Ruby, there are two current expansions, one was mentioned earlier this morning, but there will be a subsequent compression expansion. And then the Trans-Canada Project, which is basically Bison, which runs out of the Powder River in Northern Western Wyoming, over into the northern border. Now, there are a couple of other projects out here that are continuing to kick the tire, so to speak, but in my opinion they will not find that critical mass to move forward.

Just to give you kind of a timeline of how long it takes to get these projects from initiation up to in-service, we began the marketing phase of the Ruby Pipeline Project back in March of 2007. At that point in time, we entered Confidentiality Agreements with producers in the Rockies, and introduced the concept of PG&E. We met with a lot of initial positive response in the marketplace, so we moved forward through the summer of 2007 with the route selection, giving us really quite a head start from the competitors that later recognized the need for there to be another pipeline out of the Rockies. We continued to push ahead. One of the more interesting aspects of this project from being a project developer, we did something we have never done before. Because of very rapidly escalating prices in the steel markets, we were trying to find the right commercial mechanic to bring together negotiated rate contracts that gave the markets rate certainty, but yet give our Board a comfort that we could execute the total project within our cost estimate. What we ended up having to do with steel running upwards of increasing $100 a ton per week, just having in a week's time execute our transportation agreements with our shippers, receive Board approval that then allowed us to go out and place orders for a billion dollars of pipeline, binding orders, and enter into construction agreements. So back in June of 2008, El Paso Corporation was into the Ruby Project for over a billion dollars worth of commitments.

We have continued pushing ahead. An important milestone that Richard just mentioned was in November, we received the final CPUC approval for PG&E to hold their Ruby contract, and then we filed our 7(c) certificate with FERC on January 27th.

Here is a list of the shippers that are backing Ruby. You can see that it includes many of the bigger producers out of the Rockies, we basically have about $900,000 a day of shipper commitments out of the Rocky Mountain producers, on top of the 375 committed by PG&E. One unique aspect about Ruby that I wanted to touch on, it will be the first pipeline in the nation to pursue a carbon-neutral footprint. This has actually been a collaborative process between the project developers and the shippers. As the project developer, we looked early on for what could we do to mitigate Ruby's fuel usage once it is up and running, and basically any gas venting or leakage, so we had an extensive team throughout the corporation that did an exhaustive look of very creative ideas and then we prioritized them. We ended up doing very careful selection between gas fired and electric motors for the pipeline, ended up -- we will be using, for example, welding at all the compressor stations instead of bolted phalanges to minimize any Methane leakage. But, you know, a complete exhaustive look to minimize our carbon footprint. Now, that does not mean we will not be using carbon once we are up and running, or can we negate the fact that we use a lot of diesel fuel through the construction. All of those components will be off-set through the purchase of offsets.

Shown here is a picture of my boss, Jim Cleary, he is the President of the Western Pipelines, and on April 21st, we participated in a groundbreaking just not too far from Sacramento here. Ruby's first step in offsetting its construction carbon footprint is to do a 50,000 ton offset by reforestation in the Plumas National Forest, which is also very helpful for the town of Quincy because the forest was very damaged in a fire, and this will, in addition to offsetting the carbon, it will help the logger shift.

I mentioned that this was a collaborative process. Ruby is putting in about $30 million of additional capital upfront that is on our bill, basically. We are not collecting that since we have negotiated rates. And the shippers on Ruby have agreed to allow Ruby to go forward and purchase voluntary offsets and pass those through as fuel mechanism in the future.

I thought I ought to touch a little bit on the market outlook, on why Ruby made sense then, and why we think it makes sense now. I did touch on the fact that I think we had the first mover advantage. If you think back to that first map El Paso has and its footprint in the Rocky Mountains, we are probably the first party to see that there was a need for another green field expansion closely on the heels of Rex. When we were looking at where that expansion should go, we were also monitoring and watching the decline in Canada in production, and also the increasing market there. So it seemed to be a natural marriage to connect the growing Rockies supplies to basically the West Coast where they were very much lacking supply diversity.

Now we have talked this morning about the turn-back in rigs and I agree with everything that has been stated to date. The Rockies has seen a very significant decline since last August and October. Yet, with even a 60+ percent decline in the drilling rigs, we have yet to see a decline in production. This is basically showing -- we daily monitor the production that flows out of the pipelines, we add our own production capacity we deliver to the front range of Colorado and net out storage, and it gives us a very good indication of what is going on in a production side, and you can see it has been holding fairly steady.

As a way of historical view, it is not the first time we have seen this significant turn-down in the Rockies. As you look at 2001-2002, the rig count dropped off by 25 percent, but the number of wells only declined by 7 percent. You have a phenomena going on where the first rigs that get turned back are the most inefficient. Then, back in '94-'96, when the number of wells fell by 53 percent, the region was able to maintain a flat production profile. So I think I agree with almost everything I have heard today forecasted on the shales, and other production forecasts, but I would not discount the Rockies and call them dead; we still have a very robust projection for the Rockies.

Shown here is our internal projection. The dotted line shows our 2008 forecast in August. We have updated that, in fact, we are updating that almost on a monthly basis, monitoring the rig count today. This is about the first time I think we have in our history forecasted a flat production profile out of the Rockies, but we are only forecasting that for a very short period, anticipating that will resume its growth curve back in the mid-2010 time frame. Between 2007 and 2017, we see another 3.2 Bcf a day of capacity coming out of the Rockies. If you back into the capacities of the new projects that I have mentioned on that first couple slides, that basically will accommodate -- those new projects will accommodate this level of growth.

Here is a look of Canada vs. the Rockies and on the left side of the chart is actual production shown for the Rocky Mountains and Canada, in total. We, like others, are forecasting a decline in future Canadian production. I personally adopt the higher line that incorporates the shale development in Canada because I do believe it is there and moving forward as witnessed by the activity in the Montney and Horn River Basins. However, it changes the decline rate, but it does not change the name of the game. Canada will still be in decline and the Rockies will be growing. We are forecasting Rockies growth to not peak until about 2035.

There is a lot of information on this slide, and I am only going to touch on a couple aspects of it. This is basically how we look at, when we are designing projects, what will be the impact after a project goes into service, and will it be running full and provide market benefits, but shown here is the AECO Hub, rocks representing the Rocky Mountain pricing point at Opal and San Juan Basin. When you go around AECO, you have about 12 Bcf of capacity heading east with fairly high fuel rates; heading to the west, you have about 2.6 Bcf in capacity. Once Ruby goes into service and has about a 1.3 to, say, a 4 percent fuel coming out of Canada, you will see it will have a significant dispatch advantage. In the lower hand, we have shown what the futures price would indicate a price benefit coming into California from Ruby vs. coming out of Canada from AECO. Basically, the forward curve today is placing 2012 price at AECO at $6.35, the Rockies at about $6.07. When you add fuel on top of that, you see you come in from

Canada at a delivered price at Malin of about $6.60 vs. about $6.14 out of the Rockies. Because of that, we anticipate Ruby will be running full from the day it goes into surface, and providing significant cost advantages to California and markets in the Northwest.

The block in light blue on the right side of this slide, I have included just because there continues to be some discussion of, well, should we have built east or should somebody else build east out of the Rockies? One project is out there still trying to market; I do not believe they will find support because there is not enough supply. But to just give you a pricing difference between heading west and east, the Rocky Mountain Alliance Project, in order to pull gas from Opal all the way to Chicago, would have a tariff of $1.50 on Rocky Alliance and another $.18 on over-thrust. So basically, when you look at the more favorable price of $7.07 in Chicago, but net out transportation and fuel charges for a new project, you see you would netback a $5.23 into the Rockies, where a similar netback off of Ruby is netting back a $5.69 advantage. That is another reason why the producers broke trend from their traditional path of heading east out of the Rockies and chose to head west.

I did mention this pipeline is being sized potentially to be 1.3 to 1.5 Bcf. We are requesting in our Federal Energy Regulatory Commission the ability to stage the fourth station of the Ruby pipeline. If we do not find adequate support in the near term, that fourth station could be delayed up to four years, meaning that the initial capacity when Ruby goes into service would only be 1.3 Bcf.

Shown here are the areas we continue discussion in the marketplace for additional contractual support. At this point in our project, it is fully a challenge of execution, and I can guarantee you, the Western pipelines are very very busy on doing an exemplary job on this project. We received information from FERC last week that they are on track with what was our requested schedule for a Draft Environmental Impact Statement in June and a Final Certificate in January of 2010. This will allow Ruby to basically, once we receive our notices, to proceed. We will likely begin construction on compressor stations first, but we will have seven spreads fully engaged beginning July of 2010. We hope to be completed with the pipeline construction by November of 2010, prior the snows, and in service by March 1st of 2011.

This is just kind of a summary. I did mention we have purchased the pipe, the compression is ordered, we have entered into contractual agreements back in June with four contractors, they are by our side in the planning of this project, and we expect very smooth execution. The feedback we have been given from the FERC staff is that this is perhaps the most meticulously prepared Certificate they have seen. We have had a lot of folks ask questions about whether or not we can finance this pipeline and I thought I ought to touch on that because it is definitely a challenging time in the financial markets. What is shown here is what we have been doing at a corporate level. Back late in 2008, we did place a half a billion dollar bond, unsecured, at a 15.2 percent yield. However, we subsequently, later in April, placed another $500 million note at 8.25 percent, the issue price, and 9.25 of yield. What this shows is that El Paso is doing what it needs to do to keep our balance sheet fortified to meet existing demands, plus fund our capital obligations which include Ruby. And though the rates are higher than what we would have forecasted in a year, there is money out in the marketplace.

The key takeaways, Ruby is running on time and we do believe it will come in on budget. The market fundamentals that were in place in 2007 that supported this project are really even stronger today, as was supported by Gordon Pickering this morning when he was talking about the development of all of these shales, and even the Marcellus shale moving into the East, leaving Rockies gas with more impetus to push West. We have initiated a very groundbreaking GHG mitigation measure that has been well received in the marketplace. The pipeline will have investment grade metrics. If you go back to that shipper list, you can see the likes of BT, etc., PG&E, that is what we will be using as our borrowing tool because we will be using those revenue contracts as security for any lending.

The last point, we cannot tell you the exact sizing as our marketing continues, but it will be a minimum of 1.3 Bcf a day, and at this point, it is all execution for us. That concludes my presentation.

COMMISSIONER BOYD: Thank you. We appreciate that. That is very thorough. Any questions, folks? None? Thanks very much.

MR. TAVARES: Thank you, Tom. I just wanted to make a comment. Anybody who is tempted to leave, we have a major sports figure online as a speaker today, so do not leave. With that, we have a change in the agenda. Leslie Ferron-Jones is going to speak for TransCanada, and then we will follow with Don. So, Leslie, why don't you go ahead?

MS. FERRON-JONES: Thank you very much for having me here today and I appreciate Don trading places with me on the agenda. I probably scheduled my flight a little too closely, so this is a big help for me. My name is Leslie Ferron-Jones and I work in the U.S. Pipeline's Western Division of TransCanada Corporation. I will go ahead and jump in. This is the long way of saying I do not know what is going to happen. And this is TransCanada Corporation. We are a $40 billion in asset company. We have about $18 billion committed in capital projects over the next few years. We own pipelines which is about 60 percent of our income, and power plants, there is about 40 percent. So we are not in the ENP sector, or in other sectors. We have nuclear generation, coal, wind farms, gas fire generation in our portfolio. We also have interest in a couple of LNG terminals in the Northeastern part of the Continent. And more recently, we are getting into power generation lines, which are those dotted white lines you see in the Western U.S. from Montana and Wyoming, heading down to the southern part of Nevada. We have been a gas pipeline company and currently we have under construction an oil pipeline called the Keystone Project, which runs from Alberta down to refineries in Oklahoma, and there is an expansion of that project underway. So we have got a number of things going on. Someone asked earlier about kind of the willingness of industry to invest in these current times. Our willingness is very high. We have about $1.5 billion net income at the moment; as that $18 billion in capital project comes on line that will increase, causing cash flow of somewhere between $4 billion and $5 billion in the next few years. We peel out a billion to pay our dividend, and the equity we have to spend is somewhere, you know, between $3.5 or $4.5 billion. Combined with debt, that means that we are looking for projects in the vicinity of about $10 billion a year. And what I have noticed in these times, as it were, if these were to continue, in particular, is we very much want to continue that investment, absolutely. And there is no shortage of things to look at to invest in. However, we are only going to pick the very best projects in terms of financial returns. The energy infrastructure business is a long-term capital intensive business and we are looking for investments that are going to be good for 30 years, and that is where we are going to allocate our capital to. Sometimes, I work on the gas pipeline side, and producers will be annoyed with me because I will not agree to a 10-year contract on a new build construction, that is not something that I can take and recommend to my company; and the reason why is things change a lot in that window, and that has been one of the themes throughout today is, what was true 10 years ago is not true today, or sometimes what was even true last year is not true today and, again, we are looking for those long-term shareholder -- very long-term types of investment at TransCanada.

So I have got a few projects to talk about and I picked the ones off that map, and other things that we have going on, on the gas side, gas pipeline side, and that are most directly related to the Western United States. And the first one is the Alaska Pipeline Project. I think the question came up earlier today is will anyone bother with Alaska, given all the shale gas? And I think my answer is we are going to find out fairly soon. So TransCanada, we will first give some specifics about the Alaska Project. It is a very big project. In 2007 dollars, our classified estimate was about $25 billion. It includes a little spur if you take a look at the Alaska portion of the pipe, there is a dotted line, and that is an option to have a spur go down to develop these areas, and that gas would be liquefied and put onto tankers, and that is something that the State of Alaska required when they went through this process to move the pipeline along. It would be a 48-inch diameter pipeline, that is relatively big in gas pipes; it is 1,715 miles long, and that is the red area from Prudhoe Bay down to a place called Boundary Lake, which is on the west side of Alberta there. The gas would then go into pretty much existing infrastructure that belongs to TransCanada and then we disseminated throughout the United States and Canada, through the TransCanada existing infrastructure.

The major proponents of Alaska, of course, at BP, Exxon, and ConocoPhillips. ConocoPhillips and BP have joined together to also propose a very similar pipeline to this one. In terms of how things are going to shake out over the next couple of years, we are going to find out. Before we go to the next couple of years, just where it has been is, two years ago, the State of Alaska kicked off a process called the Alaska Gas Line Inducement Act, essentially they ran a bid to build the pipeline, and TransCanada was the winner in that bid; following that, and following the public hearings and so forth, the Governor signed into law a licensed bill that TransCanada had that project, and the license was granted late last year, so in December of 2008. What the state required was that the winner would have to carry out an open-season and apply for FERC in the pre-filing process, within a certain window of time. So we have a clock that is now ticking on this. We also had to commit to certain rate designs that would help with the expansion of it, that is very interesting to the state of Alaska. We had to agree that we would capitalize the project with at least 70 percent debt; for example, TransCanada has a pretty easy time of raising money, we raised $2 billion in the last about four or five months for other projects, and we pay between 6.5 and about 7.25 percent on that, so the cost of debt is less than the return that we expect from a project, so this is the state's way of assuring that that type of relationship continues. And, of course, the distance sensitive rates for the state of Alaska, meaning that the Alaskan deliveries off this pipeline would not be subsidizing the longer haul deliveries into Canada, and then the gas being disseminated into the lower 48. So that is another benefit. These are the things that the state must have, and we agreed to provide those. What they offered under this Inducement Act was $500 million in development costs, it is matching, so we spend $500, they spend $500. The state regulatory process would be expedited as needed and, probably most importantly, or certainly very importantly from the producers, is the state agreed to provide fiscal certainty. The producers up there -- I was born and raised in Alaska, still have property there, and it is like watching a cold war between two small countries, the producers and the state of Alaska, and one of the things that is a constant source of tension is the royalties. So what the state has agreed is we will basically fix or lock in your royalties, your taxes, your other issues, for the first 10 years. And so that gives the producers a higher degree of certainty in terms of what their cost structure will be on that gas coming out of Alaska.

This was part of the response that we provided when in our bid, 4.5 bcf/d, that would be about 6 percent of the United State's demand for a sense of scale; California uses about 6 bcf/d, the initial pipeline out of Alaska would be 4.5 bcf/d. A gas treatment plan is necessary, if no one else wants to build it, we will build and own it. For those shippers that initially sign up, they have an equity opportunity to own a piece of the pipeline. We agreed to 75 percent debt -- that is very unusual at TransCanada, and that immediately reduces the toll in this particular example about $.9. To the extent that we run over in our costs on this very expensive project, we will take a reduction in our rate of return. And then you see the LNG alternative that the state wanted to have, as well. This goes a little bit toward the question of why would you proceed with this project when there are so much additional resources potentially coming on that will compete with it, whether it is LNG, or shale gas, or any of those things. So this is a partial answer, but I want to stress that those of us in this room are never going to know the answer to that question. And I think it was Gordon that talked about this earlier -- the producers themselves do not necessarily know that question. So before looking at this EIA price forecast, basically, you know, they may decide, "I've got a 10-year cost guarantee from Alaska, that is the best deal I'm likely to get, I'm going to go forward." Or they may decide, "I don't have a good enough deal from the State of Alaska, and I'm not going to go forward." But given that we are required to run an open season and that we have pre-filed at FERC, and that two of the producers themselves have also pre-filed their project at FERC, remember, it is the same, more or less, project as the one that we have, certainly both of them are not going to go. There is a window of time when those decisions will be made over the next little while. You know, these are big companies. When I go and sit down and talk with Exxon, their decisions are, "Well, I'm just not going to invest anymore in South America this year, and so I'm going to go ahead and pursue some other project." And they are not sweating out whether prices change in the United States. They are very big global companies, all three of these guys. Their decisions -- we are just not going to be privy to that.

That said, here is a price forecast, I picked a third-party one, the EIA, they do a very long-term price forecast, and basically the pipeline is going to cost between $2.76 and $3.00 under this price forecast, including fuel. And so they are on the North Slope of Alaska deciding, "Well, okay, three bucks to get my gas down there, are gas prices going to be high enough to cover that?" And according to this forecast, 2018, for example, will be the first year of being in service, they have a netback of $3.77, and that is at the time we made the application; EIA updates their forecast, the one from March 2009, which is the one we grabbed, and despite all this onset in shale gas, since we submitted the application more than a year ago, the netback is even better now. So whether you believe this forecast, I think Gordon mentioned today, we see -- Navagant sees a long-term $5.00 to $7.00. You know, it is basically covering the costs of a $3.00 pipeline. That could change. And, again, I think the best

I can tell you is we should have some more information soon. And the reason why is because we are running open seasons and we are pre-filing at FERC, and when you do that, you start to spend real money on a project of this size. So we have committed to starting an open season this summer and it will last for about a year. And I believe that the competitive project has something similar in mind, at least on their website they say that they will start an open season this summer. You know, there are all these negotiations going on all the time, but I think the difference now is there is a bit of a clock on it. And the other thing that we have done is started a pre-filing process at FERC. On such a big project, that is very expensive, and we will all be spending millions trying to move the project forward, but get the shippers on board at the same time.

So this is what we have committed to do kind of in the very near future, we have to prepare what is called a Class 4 Estimate, all that means is it is a slightly better estimate than we currently have provided. We need to, because it is such a large project, we need to confirm all of the regulatory requirements and processes that are required. Part of what we need to do for the state of Alaska is complete an in-state gas consumption study, they want to make sure there is enough gas for the state's use, of course. And we need to actually have an open season plan, which is also very unusual. We know how to run open seasons, but we have to submit an open season plan to FERC, and then we need to run it, and that all needs to happen between now and about July 2010.

So I started at the top in Alaska, and now I am going to move on to what is going on in Canada that I think most directly impacts California. I do not know how much shale gas is up there, I do not know if anybody really knows, I know that we ran a couple of open seasons and a bunch of producers showed up and signed up for pipeline capacity. What we have here in BC, one called the Horn River Pipeline Project and another one called the Groundbirch Pipeline Project. The blue lines on this map are existing infrastructure up in Alberta, that TransCanada has. Essentially, TransCanada, I think of as a giant gathering system from the province of Alberta, and the idea is to bring the shale gas into the existing facilities so that it can be traded at a place called Nit (phonetic) which is one of the most liquid points in the country to trade gas. And you can see that the shales are located right next to the infrastructure, it is not a big deal to integrate this gas into the grid.

The Groundbirch Project which is coming out of the Mantin (phonetic) shale play there, and there is no doubt that Canada is well behind the United States in developing shale resources, but nonetheless, it is just a little pipeline, it is only 77 kilometers long to get it over to the grid. We have got binding commitments for 1.1 Bcf/d, it is expected to go in service at the end of 2010, and we have ramped up to that 1.1 Bcf/d by 2014. The other one that is ongoing is called the Horn River, you see there, it is 155 kilometers, again, that is a very short pipeline. It will go into service later, in the second quarter of 2011, and it has 378 Mcf. So between the two of them, it is 1.4, 1.5 Bcf/d that is going to be coming on fairly quickly into the Alberta grid, that can then be sent to the lower 48, maybe some to California, maybe gas will go elsewhere. Whoever pays the most will get it.

Moving into the United States, into the Pacific Northwest, we have a project called Palomar Gas Transmission. This is a map of Washington and Oregon. One of the things I want to mention, and we will make sure to follow-up with the staff here at the CEC, the GTN pipeline, which is the green line you see cutting down from Canada to the California border, to a place called Malin. That is the GTN Pipeline, and so right now I think our market share of the gas, if you will, that California uses every day in Northern California, is about 47 percent coming out of that green line. If you look at California as an entire state, the gas coming out of that green line is about 18 percent. So we are an important part of the infrastructure that delivers gas to California. The top of the green line is 3 Bcf and the bottom of it is 2-2.1 Bcf. And it is not really possible for the Pack Northwest to kind of steal -- I heard a little thought of the gas is not really, or the capacity is not really 2 at Malin because the Pack Northwest could take it away; that is not really the case. Again, the pipeline is like a big funnel, or a telescope that you pull out, it is wider at the top and smaller at the bottom. We can deliver a Bcf into the Pacific Northwest, that is 3, but we cannot deliver more than that. And they cannot take it away. I mean, that is not to say that years from now there might be construction that would change that dynamic, but that is the dynamic today. So we can deliver to, and California can take to, and nobody can take that away from them because the pipeline has been designed to accommodate all the takeaway that is north of Malin, and it is less than a Bcf/d. But anyway, the

Palomar Project is kind of the first part of a chain that needs to happen for the Pacific Northwest to meet some growing load. The Pacific Northwest, like California, has renewable portfolio standards they are trying to hit. Unlike down here, solar is not an option. I live in Portland now and it rains all the time. But wind is very much an option, so they are building a lot of wind farms, those utilities, and they plan to build more, but they do need the gas fire generation to firm up those loads. And so what that means is they have some growth in the electric generation side for gas fired stuff. All the load is in the I-5 corridor between Seattle and Portland. There is one pipeline that goes over to that corridor, Northwest Pipeline, and they have an expansion project called Blue Bridge to build from the green line at the Oregon-Washington border, west near the existing infrastructure, you see the yellow line, basically to loop that system. And we have a competitive alternative we call Palomar, which is this teal colored line there, that would leave from our system at Madras and essentially cut over to Portland, and that is the eastern part of that project, and that could bring Canadians gas, it could bring some of that shale gas, it could bring Rockies gas from another project, and then the line further extends west, and there you see to the very western-most border between Washington and Oregon, and that was to serve a proposed LNG facility called Bradwood Landing. That facility has received its FERC certificate and continues to be developed. And as to the question of whether or not LNG will come to the West Coast, from my perspective, I do not know that it matters a lot. That project has spent a lot of money, and it will probably continue to spend money until gas supply is ready for it; that does not mean it is going to go into construction, it has got its permit, and it is going to wait for gas supply, or someone else to contract for that capacity before they were to go into the next level of spending which is construction. But it has got its permit and at some point in time, if LNG wants to come to the West Coast, it will have a choice to either go down to Costa Azul, expand Costa Azul, go after some other project, or go after this one, which has already got its permit. The Palomar Pipeline is filed at, so we filed the FERC application, and we would expect a preliminary determination around September of this year, and a FERC certificate around April of 2010, and it can be in service in November 2011. Now, the Pacific Northwest, remember, they are backing up wind farms here, and they do not want the service until at least November 2012, but we will have the FERC certificate and be ready to go with them when their timing is right. And one thing about the current economic times is, they are not sure November 2012 is right, it might be November 2013, we are just going to have to wait and see how their loads go. The Sunstone Pipeline is a project that would go from Opal, the Rockies Basin, up to the middle of our pipeline at a place called Stanfield. There is nothing at Stanfield, well, there is not much, there are a few power plants, I should say. But it is designed to feed into that growing load into the Pacific Northwest, so it can either go into the Blue Bridge project, which is our competitor, Williams Project, or it could go into the Palomar Project, which is the one that we are proposing. Somewhat interestingly, Williams is our partner on Sunstone, but our competitor between Blue Bridge and Palomar. So, again, this would be a November 2012 in service date, unless they tell us that they want it to go later; it is about $1.9 billion, and targeting a capacity of about 575 million cubic feet a day. Originally when we proposed this, we were trying to get California load on it, we do not have any California load and I do not think we have any particular California prospects, and so we have redesigned it, re-scoped it, for the later in service date, which is what the Pack Northwest wanted, and a smaller design, instead of a 42-inch, it is a 36-inch line.

Pipeline costs -- the cost of steel came up earlier and one of the things that we found with Sunstone is, by moving our start date to later, we are able to take advantage of the current low price in steel. This is a forecast from a vendor that almost any pipeline company had, they are called Global Insights, a lot of people subscribe to them. And so what you see are the solid lines are historical prices for steel, the red line is steel plate, the blue line is X-65 line pipe; that is just a common pipe that is used in the industry, just illustrative. And you can see that prices ran up on us there. And one of the reasons we like Sunstone so much is the shippers that are in Precedent Agreements are all 30-year cost-based shippers, and so they are taking a risk on this, and they have been willing to go through that. But the good news is that prices are way off now and, in the forecast, you can see Global Insight keeping it fairly flat, and then eventually increasing again in that vicinity of 2011. We have seen it go down even further, and that is good. I mean, that is very good, it will continue to help us develop these projects. So where Sunstone is at, in order to make a 2012 in service date, we are looking for shipper commitments by the end of June of this year, we would then place orders in May 2010, FERC certificate in the second quarter of 2011, and have two years to construct it. That is pretty conservative, but that is okay, we are very conservative, both Williams and TransCanada, and an in service date of November 1, 2012.

Lastly, the North Baja Pipeline is our southern-most asset, at least on the Western side. We do have a pipeline in Mexico and we have agreed to build another pipeline for the Government of Mexico. But this is North Baja, the kind of maroon line, Gasducto Bajanorte is the teal line, we operate that pipeline for Sempral, and we own the North Baja line. And I think the only thing really going on there is the Yuma Lateral is something that we will probably start construction of this summer, and it is to serve about an 80 million a day power plant load for APS in Arizona. So it is just a little lateral that would go over to Yuma. It is only about 8 miles long. But that is the new load that has shown up down there.

The last thing I will leave you with is just some thoughts. The more thing change, the more they stay the same. And I am just struck by a lot of what has been said today. This industry is long-term and capital intensive, and it goes through these very unpredictable periodic shifts, and we are in another one now. When I started with this company 12 or 13 years ago, I was an Analyst and I was catching up on how the business works, and everything said that the San Juan was in rapid decline, it was going away, it was drying up. And there was this massive gas bubble in Canada, and Canadian gas was really cheap, and so a lot of infrastructure was getting developed out of Canada. But then, very quietly, the San Juan got a bunch of tax credits and essentially invented coal bed methane, and they are still doing fine, and now it turns out there is a ton of shale. So, you know, call it anything but dead, or even declining is risky, and you are probably wrong, and it is only a matter of time until that turns up, it is one of the things that I have taken away from my time in this business. And the same thing out of Canada, a lot of infrastructure. Because prices were so low up there, it got developed out of Canada. I disagree with some of the statements made earlier, quite strongly in some cases that Canadian gas is in decline. Our forecast has it basically flat, and then you have to figure out what shale is, and we do not know, but we are always looking into it. It could be a lot of gas, but it does not mean it is going to get developed next year, or five years from now, it may just sit up there for a while. But there is no doubt there is a lot of reserves, a lot of gas. And TransCanada is a very long-term company, so we try not to make too many decisions based on this year's price forecast, or this year's production forecast, it is more about reserves, where they are at, and the pace at which they are going to come out of the ground. There is a lot of reserves in Canada, there are a lot of reserves in Alaska. We would love to have more Rockies investment, a lot of reserves in the Rockies. And then, lastly, you know, what gets us through all this is the market does decide, it does pick, you just have to wait until it is ready to do so. And we are perhaps there on a couple of major projects, we will see how the next couple of years go there.

Any questions that I can take?

COMMISSIONER BOYD: Well, thank you. I sure agree with your conclusions, I guess we both learned those things after spending some years trying to figure out natural gas. I happened to see Governor Palin last Wednesday, I guess, oh, that was yesterday, wasn't it? I guess I saw her Tuesday, and she certainly is high on the pipeline project, and even said some good things about TransCanada, you will be pleased to hear. In any event, thank you. You answered a lot of questions. Those people think it is summer up there, it was in the '50s and they were all wearing t-shirts, shorts, flip flops, and I have got a coat and a shirt.

MS. FERRON-JONES: I arrived here today and I am just a little worried about how hot it is going to be when I try to get to the car on the way to the airport. It is very very warm here.

MR. COX: Hi, Rory Cox from Pacific Environment. The Sunstone Pipeline, it looked like it was going to connect to the Palomar Pipeline, and the natural gas, it looked like it was going to the Bradwood Landing LNG Terminal, which does not have a lot of -- it is not quite a market. What is the purpose of that gas going there?

MS. FERRON-JONES: That is a great question. I am sorry I did not explain that more clearly -- very good question. So the gas on the Sunstone Pipeline, the Sunstone project will go to Stanfield, and from there, the gas can go wherever it wants to go, so it will theoretically get into one of the projects to serve the Pacific Northwest load, either Blue Ridge or Palomar. There is not enough existing infrastructure to take it, they need a new project, either Sandstone or Palomar, presumably. No one expects the Bradwood Terminal to go forward in this period of 2012, you know, 2013, that these two pipeline projects are expected to go forward in. The utilities there cannot bank on that terminal being there, but they need this gas in that time frame to back up their wind farms. So it is possible, let us say 10 years down the road, that the Bradwood terminal is constructed, one of these pipelines, say Sunstone, exists plus either Blue Ridge or Palomar exists. And the way we designed Palomar is that it flows bi-directionally, so the LNG gas could get into Palomar, come back -- and that gas, there is too much of it to serve the Pack Northwest -- that gas would come into the GTN main line and head south to California. So it is really a timing issue; while it is nice that Bradwood has its permit, and we will definitely try to get Palomar permitted all the way there, nobody is expecting that in the time frame that these utilities need the gas.

MR. COX: Right, the Bradwood permit is conditional?

MS. FERRON-JONES: Oh, yeah. Like any permit, it has got hundreds of conditions on it.

MR. COX: Right. Thanks.

MS. FERRON-JONES: Thank you, guys, very much.

COMMISSIONER BOYD: Thank you.

MR. TAVARES: Thank you, Leslie. Next, we have Don Peterson and also we have Mark Hall from PG&E.

MR. PETERSEN: I want to thank the room for continuing to hang around. I am not sure if we should do a set of jumping jacks, this has been a marathon all day and so, thank you. And if I still have half your attention, I feel honored at this point.

Mark and I are going to do a tag team. I am more from the pipeline side of PG&E, and Mark is more from the energy procurement side, and we have got slides that deal with both. Our primary focus today is going to be on infrastructure because that is what we were specifically asked to address. We are only going to talk about certain of the questions in which we thought that we brought a particular PG&E utility perspective. Others in the room, as you have heard all day, have addressed some of the broader supply questions in the West and nationally, so we are not going to touch on those.

Here are the topics we want to look at today. There were two specific questions that the CEC asked, one about natural gas storage, which I am going to show you a slide in a second which Bill Wood's report largely covered that, I do not think we are really adding anything new there, but we want to be responsive. We also want to talk about some concerns we have for our infrastructure and some plans. We have an expansion possibility coming up which you will be interested to hear about. We also want to tee up for the workshop that is coming in June, The Intermittent Generation Issue. We are just going to try and maybe wet your appetite a little bit today, we do not want to dwell on it. But intermittent generation, to back up wind and solar, has some potential issues for the gas system, and we are not sure if the gas system is largely being taken for granted at this point, or not, or whether or not it is just something that the industry needs to study. And we are going to be recommending that the Energy Commission, in the EIPR, look at the Intermittent Generation issue, so I just wanted to kind of flag that before we get to it. Then, lastly, Mark is going to share some observations about the West and natural gas supply from PG&E's portfolio perspective. So let's get going and we will turn you over to Wayne here fairly shortly with El Paso.

Again, these are numbers you have heard so far today. We, just to be polite, kind of cut the list at those who had filed for CPCN's, there are other projects out there, particularly the Nicor Project which is starting to do some test well drilling, there has been some trade press about that. But again, I do not think there is anything new here that you have not seen today.

The point that I want to leave you with here about storage is the fact that our system, interestingly enough, is becoming counter-intuitive; we are starting to see higher summer flows on the backbone system than in winter. And if you stop and think about it, you think, "Gee, there is larger demand in the winter, why is that the case?" Well, the case is because there is so much storage that is coming to Northern California, or that is either here or coming, that with the interest in the market to refill storage during the summer, it is pushing up flows on our backbone system in the summer. And I am going to show you some slides here in just a moment that demonstrates that. This just kind of gives you a sense about things basically doubling, particularly on the withdrawal side over the next several years.

Making the obvious point here that gas demands peak in the winter, and then a summer period in August where you get the electric generation load, but receipts are in the spring and the fall. And the flowing supplies represent basically the blue, and the red line on the colored, you cannot obviously see it as well on the black and white, is demand. And so you can see demand is following what you would think, it is higher in the winter, with the peak in the summer, but look where the flows are. It is more so from the spring, summer, early fall. That has the potential to -- that is where I am heading with this -- strain the backbone capacity in the summertime. This is the graph that begins to demonstrate that a little bit further. Let me give you a cautionary note about the right-hand side, notice that the scale changed there, it is 2008 to 2011, it is not a one year at a time number. So we did that just to kind of be able to reduce it so that it was more easily visible, I think focused on the end point, not the fact that the trend is at a 45 degree angle there. But you will see how the winter flows we are projecting are going to continue to go downward and the summer flows are going to continue to go upward. That is the point I want you to take away from this. It shows a little bit of history, monthly average backbone flows; if you are looking at the black and the white, the green line, which is '08, the most recently shown here, is the top line. You can kind see a general trend upward, particularly in the latter month 6 to about 9 to 10. And that is an overall long-term trend here, too, not just from '08.

Getting at the adequacy of capacity, we made our filing last summer, it comes out of the gas capacity EIR that Richard had talked about earlier today, and the conclusion under the planning criteria that we were using for the study was that PG&E had plenty of capacity, the same way SoCalGas said they had plenty of capacity. If you look at the far right column, using the criteria that we were asked to, we are showing about 75 percent utilization, at best. And I think this is, again, could be perceived as contrary to what the staff report was perhaps hinting at earlier today, and hence we do have some concerns we think we need to really sit down with Bill and the rest of the staff and see if can just kind of sort out why we would seem to have some different conclusions here. But this met the criteria for what we were doing for the CPUC, per their order. Now, the comment, though, is that while it meets the slack capacity criteria of the Commission's order, as Richard very aptly pointed out, there are a number of reasons why you may want to expand your system. You may not have to do it literally for reliability, and our first obligation is to serve core reliability, but the market may want to do an expansion. I think there was a comment about a constraint, well, if one particular part of your system is flowing full, and that happens to be the preferred basin where markets want to bring gas in from, you very well may see interest from the market in expanding, and this is going to be a comment that is going to apply to the Baja path, our southern path, specifically, as you will see here in a moment.

So we have adequate backbone capacity to accommodate forecast demand on a system-wide basis, but that there are benefits from expansions and particularly as more storage is developed, there is going to be a need to refill, and you can have debates about whether or not it is a pure liability, is it an economic price incentive reliability, are you trying to avoid price run-ups at the PG&E Citygate because you could get a particular path that is running too full, does that kind of blow out a basis at a particular point, i.e., the PG&E Citygate? So, again, a number of reasons why an expansion might be in everybody's best interest.

Based on everything I have said, you probably gathered that, yes, we think the market has an interest in expanding the Baja path. In fact, we had put out a notice last Friday indicating basically stay tuned, we anticipate an open season here very soon, we have at least temporarily postponed going out immediately with the open season; keep an eye on the PG&E website. Like I say, it was postponed, it was not canceled. I probably just cannot say anything more than that. But it would not be surprising to have an expansion here very soon that, if the market supports it, we would file with the PUC for approval. And if we did, we would also be including this as part of our rate case application, which we have an obligation to file by February of next year, this is for rates on the PG&E backbone system. We will file some time between September and February. February is really a drop dead date, you could not barely process the application in time to give the PUC time and interveners to participate, and still get decisions made and new tariffs issued for a January 1, 2011. So our expectation is that we will be in before February of 2010.

A point with some of the expansions in the Northwest that are proposed. We believe, based on the modeling we have done at the Baja path, it is going to continue to be a path of high demand, even with a Ruby or Sandstone, or whatever happens in the Northwest. The market likes the Baja path and we think that that is going to continue to be true, regardless of what happens in the north. But as, I think Leslie was saying, I mean, you are just going to have to wait around and see what is going to happen, nobody knows.

I wanted to move quickly, and this is a little bit out of sync, but, again, we are going to tee up the issue of Intermittent Generation. We are becoming somewhat concerned that the gas system may need some tweaking to accommodate the backing up of wind and solar. Up until this point, due to the lumpiness of improvements to the gas system, we have been okay with the level of wind and solar in our service territory, but, as you all know, there are huge leaps forward in the number of megawatts between the two resources being contemplated, and at some point the local areas of your gas distribution system and the local transmission system may not be sufficiently sized to accommodate some large scale swings, and what we are particularly concerned about are the intra-day swings, not the ones that you have got one or two days leave notice, long leap time notice, but literally a couple or three thousand megawatts of wind all of a sudden stops blowing, or all of a sudden starts blowing, you cannot just turn the dial on the gas system and have everything just be fine, and assume that is going to work. So it is an issue that we are not alarmed at this point, but it is something that we feel that all of us collectively, we want to integrate renewables, are going to have to take the gas system impacts very much into account. They can be dealt with, but they should not be taken for granted, I think, is the message we would like to leave you with. And if the CEC can bring this into the IEPR process at some point, we feel like it would be beneficial for everybody, so just a request, if possible.

COMMISSIONER BOYD: It is -- I mentioned in our scoping heretofore this IEPR, so it is something we are concerned about taking a look at.

MR. PETERSEN: That meets our concern. Thank you, Commissioner. At this point, I am going to turn it over to Mark and he is going to leave you some thoughts about the supply situation in the west.

MR. KOLB: Thank you. Thank you for taking the afternoon to hear us. Again, my name is Mark Kolb and I am with the Energy Procurement Organization, which is essentially a customer to Don's side of the house, the infrastructure side. My organization works with both the core portfolio and the portfolio for the electric -- the group that buys the gas for the electric bundled electric portfolio. And, again, PG&E is here to talk about infrastructure, the third topic of the day, and I will give you a little bit of perspective from the procurement perspective.

Among the objectives that we have from the Procurement Organization that is really the most relevant are probably the two that deal with supply, we have a very big concern about ensuring supply reliability, and competitive costs for our customers. Now, I am talking about -- I will talk about three aspects of where infrastructure intersects with that. The first, this is actually the last slide that Don mentioned about intermittency and its impacts, and that is one actually we are working together with the gas transmission side of the house, and thinking through on what are some of the impacts of the increases in the increments of wind. And then, also, what would be the potential implications for our procurement entities, and particularly the electric generation one, in terms of increased needs for balancing or other types of solutions that might come out of this, not just one effort. And I think we are going to talk more about that later on in the year. The second, and that is not so much on the slides here, but it is a reaction more to the paper that was provided by Bill Wood earlier today in the study providing supply and demand balances under stress conditions. And, again, our comment is generally that is an effort that we think is very useful. As Don mentioned, we have specific concerns about some of the inputs and the particular methodologies that Bill walked through today, but that is a very healthy exercise, it is one that we do for both of our core portfolio and for the electric generation portfolio. In the most recent -- there has been some PUC proceedings, the one that has been mentioned earlier here today, the 2004 gas past OIR when there was some analysis of those holdings and how we have got to deal with the stress situations. Also, the incremental core storage application, there was an analysis for the core portfolio, and in the bundled electric portfolio, that type of analysis is going in the PUC's long-term electric procurement. So that is mainly the main statements we would have, and I think in written comments we will have some particular comments about how we would approach the analysis somewhat differently.

The next part is more about what actions we would take when we look out to the supply picture in the West, and what approach we take to procurement, to again ensure these objectives of supply reliability and competitive customer costs. And in a word, the main approach that we want to impress upon you is that our big approach is essentially diversification. There is a lot of uncertainty in this market. That has been a theme that also we have talked about throughout most of the day, about which basins are growing and which ones can provide advantages. And essentially our approach is diversification in all of its perimeters -- diversification from being able to procure from diverse basins, from multiple pipelines, from having multiple pipelines at different receipt points, from being able to use the difference between storage and pipelines so that we can diversify in a sense between the timing of our procurement. And then, also, even as Richard talked about, in the reformed process for interstate pipeline contracting, we have an ability to diversify the terms of the different interstate holdings that we have.

The next three slides are just going to sort of demonstrate how that goes into action. Currently, we have a fairly diverse network and access to multiple basins, and various pipelines. We talk about the ability and the opportunity to benefit from the growing basins. There has been a lot of talk today about the growth in the shale basin, that was the main topic; but we view the Rockies, also, as an important growing basin. And in our current situation, we think we are getting indirect benefits from those incremental growths, both in the shale and in the Rockies area. Part of this is due to probably the somewhat short-term situation where there is sort of stunted development of moving a lot of the Rockies gas East to maybe a continued build-out of the shale, to move that out East, and having that simultaneously with a drop in industrial demand, and that sort of Mid-Continent, San Juan Permian -- and I am very much generalizing, I am just giving a broad view picture here -- but those together have created sort of an overhang of gas which has benefited California and benefited PG&E's procurement entities. It has probably benefited a little bit more due to the procurement entities in the south, but we have also been able to enjoy those benefits to the extent that, you know, there has been a basis discount in those different regions and that situation should continue for some time.

Looking forward, the biggest change will be what we hope is the completion of the Ruby Pipeline. Both of our procurement entities have significant contracts which were approved by the Public Utilities Commission. We think that having access to that Ruby Pipeline offers a lot of advantages, again, on both those objectives. It improves our supply reliability, not just because it is an access to another basin, but also access at another receipt point, so we have more flexibility now at Malin. And then also, obviously, it would improve the opportunities for gas and gas competition. And even though there is potentially the completion of all those pipelines going East, which many prognosticators would say could potentially increase the Rockies price, at least diminish the basis discount. As we also talked about today, there are possibilities that the shale in the East is substantial and massive and can push that Rockies back West. And with our direct access to the basin, we would be in a position to benefit from that. There are also uncertainties about how much extra production might come out of the Rockies over the next, you know, mid-term, long-term horizon, or whether even the Western Canadian gas would also start becoming more competitive looking forward on the West. But in the end, I am not really trying to give any prognostication of these supply pictures, it is just again that situations change substantially and our approach to respond to that is more or less lots of diversification of our opportunities, just a fairly straightforward message. I will leave you with that.

COMMISSIONER BOYD: Thank you. Questions?

MR. Y'BARDO: On your Baja expansion, would that include added take-away from the California-Arizona border from TransWestern and El Paso?

MR. PETERSEN: It would increase the firm capacity on the Baja Path by some extent, depending on the results of the open season and, yes, I mean, all of those upstream interconnects, be it Kern, TW, Southern Trails, El Paso, the shippers there could be competing for that space. So, yes, we would be expanding the amount of space that we would be bringing in to California from the Topock area. I think that answers your question, does it not?

MR. Y'BARDO: It does.

MR. BRATHWAITE: For the record, I am Leon Brathwaite. I work here at the Commission. Don, in our 2007 modeling work, we had forecasted the need for the Baja expansion. And this is published in our 2007 Natural Gas Market Assessment. But I was wondering, at that time, we did not consider the effect of a Ruby-type pipeline. Did I hear you correctly when you said that, even if Ruby comes in, the expansion might still be viable?

MR. PETERSEN: Yes, you did.

MR. BRATHWAITE: I did? Oh, okay. Thank you.

COMMISSIONER BOYD: No other questions. And thanks very much.

MR. TAVARES: Don and Mark, thank you very much.

We invited this afternoon -- I do not know whether you have been watching the play-offs, the NBA play-offs, and we invited Kobe Bryant to be here, but he could not make it. He has a game today. So instead we have Wayne Tomlinson and he is coming from El Paso. Actually, he started at El Paso in 1978, same year as Richard started at the PUC. He retired two years ago, but he is still working with El Paso, and he actually played basketball for the University of Tennessee. So are you going to talk about basketball? Okay, Wayne.

MR. TOMLINSON: I want to thank you for inviting El Paso to this workshop. I think this is a very important endeavor. I am going to discuss on a micro basis -- and this kind of fits in with what Bill Wood put in the staff paper -- the South System on El Paso Natural Gas Company.

I think you have seen this slide before.

COMMISSIONER BOYD: They have become rather standard, haven't they?

MR. TOMLINSON: So I do not think you need to read it again, I am sure you read the whole thing before. The first thing I want to say is El Paso believes in the basics of the methodology that Bill Wood put in his staff paper. There are a few caveats I would like to say to that, one of the big ones would be that I think you need to add the contracts to the upstream interstate pipelines. And there are a few numbers that I would probably want to tweak at this point. One of the basic questions that was put out for this workshop was that there is 10 Bcf of connectivity of interstate pipelines, but there is not that much gas that can get to the border. And I can give you a good analogy from one of our team members, George Wayne, last night said, "It is kind of like the Colorado River, it goes all the way to California, but if you do not have any water rights on it, it is going to be diverted upstream." So the pipelines are very similar. And I could give you some statistics, and this is over time, if you go back in the 1980s -- and I am dating myself -- I think the first rate case I was involved in was 8844 -- California had approximately 90 percent of the capacity on the El Paso system, and only 10 percent when to EOC. It was a short time later in the early '90s, that shifted to 80 percent for California and about 20 percent to EOC. Now we come forward to about 2004, the through-put level on El Paso System is 40 percent California, 60 percent EOC. And I should kind of break that down a little bit for you, as we have had tremendous growth, as you know, in electric power, but also in Mexico. But it has taken a big slice off our through-put and our capacity has not decreased during that timeframe, basically. But you would like this, it is almost 50-50 in 2008, it is really 47 percent California and 53 percent EOC. That shift not really -- it happened in about a year or so. And a lot of the pressure that you have got to look on a macro standpoint with Rex going in partial service, is putting a lot of pressure in the Northeast. And in doing such, it is backing in Permian. And we are only moving off system approximately about 400 a day, and I can give you an estimate of about 1998 or so, we were moving almost 2 Bcf off system because it was not going to California. And off system, saying it is getting into Texas, and it is trying to find a home in the Northeast. This and that. These are different things over time. It is kind of chronological, it is not exhaustive, but it kind of gives you what things have gone on. You sometimes look at the market, at least I have over the time that I have worked at El Paso Natural Gas Company, that things seem like they take forever to get going, and like the Ruby project, it will not be in place until 2011, and Tom has been working on that almost for two years. But you go back and look what has happened historically, a lot of things have been developed. I mean, a lot of things go on and a lot more than we really can consciously think of. But going back to 1992, we had some major expansions in California, and that is the Kern River Mojave, that was about 1.2 B's a day that were connected to California. It was a distinct market, but it was gas getting into California. You also had GTN Pipeline, approximately at the same time frame. So you had 2 B's. I think at that time, especially El Paso and maybe TransWestern, I know some agencies in California felt that there was not a need for years, and I am not talking about this 10 years, but for years that they would have enough conductivity, that they would not have to worry about supply or interstate pipelines. That has not been the case and, I mean, for different reasons. And one of these reasons is the next two tabs, is that there has been tremendous increase of gas fired electricity, not only in California, but in EOC, and when I am saying "EOC," it is not just Arizona, but even Nevada and other states. I do not think from AB 1890 that we thought that that would be the case at that time in the '90s. Because of this gas fired electricity, at least on El Paso's system, and I have another slide of this, we had to expand line 2000. And that is a per shuts (phonetic) pipe we had, and then we had to further expand because of the increased growth that we did see in the EOC during that timeframe. Like [inaudibile] mentioned, other things were happening out in that marketplace that are going to affect the dynamics of how gas flows throughout the United States, and as I mentioned what happened just this last year, the Rex expansion has already done that. You can just imagine what would happen if the shale does grow, what some people today said it is going to, and the effects, the dynamics it is going to have throughout North America with the flows of gas. I have to disagree with someone else stating earlier that the Canadian supplies hit their pinnacle in 2001, and they have decreased ever since; I will agree with the shale, that that could change that over a timeframe, and maybe they can start having an increase again, but if you go and just try to plot the supply out of Canada today, it is going to be -- it is on a downward trend. We already talked about the increase in shale production. I should put a caveat also on all of these things, but the last bullet in here has a big effect, as everyone knows, on the economy and how long this recession goes on could prolong many of these different factors that we are seeing. LNG, I do not know if I should beat this one up too much. I think a lot of people talked about it. It is very price sensitive, as put out there. It is an option, there is optionality for shale and even Sempra. It will have an effect, though, just like I said Rex expansion going East, if that gas comes in at any amount, 500 or a B a day, that will have a dramatic effect, which I will show you, which you will have more slides than you ever want to look at -- gas on our South system because that will decrease dramatically the flows on our South system. The TransWestern expansion, which just went into service and was stated today, it is moving about 200 a day into Phoenix. We are seeing somewhat of an effect on the South System, and we will not really see that real dramatic effect until the summer months when the electric loads really start moving.

Greenhouse gas, the environmental factors -- until we really know what all those rules are and how those economics will play behind the game, we are not going to know how all these will fit, and who is going to be winners and losers off this, and I think a lot of people are standing on the sidelines waiting to find out what are all these rules going to be.

Okay, the first thing I wanted to do is show you the dynamic on the South system and it had to have some correlation to something else out there, and I think I found something. And it is GTN Pipeline. And I definitely did not want to get in the pants of any other interstate pipelines because, you know, no one likes that, but in a way I guess I am. What we do on a macro sub, we usually look -- years ago, that GTN was a base load pipeline going into California, it was the cheapest gas, and that is what you are seeing what started out in 1998, you know, prior to that, and you can see it is coming in at a pretty healthy load, it is volatile like everything else, but it kind of stops around 2001 going into 2002 timeframe. And you are starting to see circles as you look through 2002, 2003, and it gets real tight when you get down to 2006, 2007 and 2008. And there is a lot of volatility that begins in the 2003, that you see the decrease that I think you can see -- I can see it here, I do not know if you can see as much on the black and white -- but in 2003, in January, the 2,000 a day capacity, or 1,800, we could argue that, there was a day in January which was, you know, a winter month, off GTN, it only delivered 300 a day to California. And someone else has to make up that difference, and that is when you see EP&G's through-put started going up, and it becomes more pronounced, so you get an inverse correlation as you go through time, and it becomes very pronounced in 2006 and 2007 and 2008. But I am just showing the dynamics of these different pipelines, one is going to have to adjust to another one as through-put is needed for California. I should say that you can also correlate this, and this is usually a slide that I show, this GTN correlated to Transco no. 6? So why this is happening is that as prices increase in the Northeast United States, Canadian supply moves to the Northeast so there is less supply that can get down to California and then the Pacific Northwest.

I should have said earlier, after the 2000-2001 crisis, I think around 2003, someone asked me what we were going to do with our South System on El Paso because it really emptied out. And at the same time they were asking me that, we were in at -- and filing for -- expansion on that South System. So it logically did not make sense that we were emptying out to a degree, but we were expanding. And you could see in 2001-2002, the capacity we had is the orange line at the top straight lines, basically, and then you see the daily volatility. And we pierced that in 2001-2002, so we had more volumes than capacity during that timeframe. But you notice, then, in 2002 and 2003, that those volumes went way down, and that is when we had to file for these expansions, and it did not make a lot of sense. But then, if you look at this graph and you look at that time frame, 2002 and 2003, and look at the slope over time, it has been growing dramatically and a lot of that has to do with the two things I said earlier, and that is the Mexican market and electrics. I am going to beat this to a ground. On the black and white, you are not going to be able to see this, but -- this top line, all same color, that is 2008. This is stacked the rest of the years. So it is showing that it has been a dramatic increase in 2008. Then I tried to change this a little bit so that it would not be as confusing with so many lines. This is just 2007, 2008, and again, you can see the top line is 2008 and there is a little bit of a separation in two parts of the year, and it is just showing the growth that we are seeing on the south system. I must say, though, these things can change. Here is a different way to look at it. And like I said, you are going to have so many of these slides on the South System. This is all from Cornudas, so my measuring this thing, it should have been a map, but I am measuring this thing as east of El Paso, Texas, so that is where gas is coming in off of the Permian Plains area, and going South, going through Texas, New Mexico, Arizona, and hitting the Ehrenberg. And you can see the last year in 2008, a dramatic up-shift, even from 2000 and 2001. Okay, different way to look at it. Some people are just better with numbers instead of graphs. If you look at an annual day average used on the South System, you will see that in 2001, that average was 70 percent. By 2008, it is 68 percent. And by those two different dates, we have increased the capacity on that by 500 a day. So it has been a dramatic uplift, but that is not the only -- the best way to look on how the usage of pipeline is. Sometimes they are used just on a peak, so the people buy for the peak, so we have a slide for that. And on a peak day basis, you can see in 2001, and I showed the other graph, that we pierced the capacity, and it was 103 percent in 2001 -- look what it is in 2008 -- 94 percent, and it has a pretty high load factor the last three years, basically. So it is being utilized for the South System. Another thing to notice here is how much lower it is in '97, '98, and '99 at the crisis, 95 percent 1.03, and in 2001, then the slow decline, and now it is starting to go back up. Again, this is off Cornudas, this one. There should have been another map in there, and I was going to explain how things work, but I will go through this very quickly.

What I explained verbally is this part of it is the plains, you have got Wahog (phonetic), this is our South

System, comes up through here to Ehrenberg. This system was originally built, you go East to West, which makes sense, this is our San Juan cross-over, it is called a cross-over because it does not go East to West anymore, it goes West to East, so San Juan Gas goes both ways. And then we have certain things that Bill Wood mentioned, this is the Maricopa Line, going by the middle of Arizona, catching into Phoenix, has a capacity of about 130 a day. This next line going down from the north to south, connected basically at Topock, going into about the center of Arizona towards South System line, that is our Havisu line, and the one that Bill really described was the line 1903, and what happens is we move gas from Topock into Mojave, and it goes South into Ehrenberg and gas goes on our South System. The capacity is about 2,400 a day as it gets in here on the South System, and so that was when I was measuring all of those percentages that you just were looking at. What we can move down from the North to the South on the West end is approximately 1.1 a day, so there is about a 3.4 and 3.5 a day that is getting in on the South System, quite a bit of gas. Now, the Knoll Point, in other words, it used to be in the old days that we did not have all this North to South transfer, so everything was moved in on the East end, and was going all the way to Ehrenberg, it was going to be used in California. That is not the case today. And if we are only moving 900 a day into California, we have enough transferring capability that it means that some of this gas has already gone east, then the Knoll Point is somewhere between Phoenix and Ehrenberg.

Now, on the previous analysis, I think I beat that horse to death, so I am going to have to change horses, and we are going to look basically at Ehrenberg. And one of the things that we have not looked at is contracts. And like I said, I think what Bill Wood needs to do is incorporate the contracts because, if you do not have this contracted on a firm basis, more than likely, it is not going to come to California. If you are looking at 2009, we have about 412 Endeco therms a day, signed up for; California Companies, producers are about 425, that comes to just an average basis of about 50/50. Our Delivery/Receipt Capacity is about 1,210,000. You are looking at a 71 percent, a 65 percent, and in 2010, that is contracted.

What I am going to do now is I am going to add in -- I am going to use the Ehrenberg capacity, that 1,210,000 and I am going to go through just a couple slides, I am not going to beat this to death. You can see during that 2000 timeframe, that is a very high utilization on an annual average day, and it is not as high in 2008 and 2009, and you are going to think we have much more capacity available out there, it is going somewhere else. But then you need to really judge this again on a peak day. What is happening on that one peak day when you really need the gas? Kind of unbelievable. This is just at Ehrenberg, with us having 3.4 or 5 capacity in total of supply getting to the South System, we are moving in abundance of that 1,210,000 capacity at Ehrenberg. At the 2000-2001 timeframe, 105-106, but if you look at this last four years, 99, 98, 96, 94 percent. Very high load factors.

So I wanted to go back to that first slide that I showed you on the Ehrenberg in North Baja and the annual load, and here is another delivery point that was alluded to earlier by GTN, and that is the North Baja, so we have a delivery right next to California Ehrenberg, SoCal Delivery, which happens to be North Baja, and it is taking gas down to Mexico. The load factor on that today is about 250 a day. What I did was I took that 250 a day and added that in with the Ehrenberg through-put, and then I divided that by the 1,210,000 because, in essence, the North Baja, you could assume, is taking away through-put that could have moved directly into California and be utilized by California instead of Mexico, and you can see the load factors, especially the load factor in 2009 is higher than 2001.

So the key points we should take out of this, and I just want to remind you that you will forget about this later on, and I want to write this in here, that I used the capacity at North Baja in that last calculation, but that what I stated earlier, capacity is available on El Paso today, and if you want the through-put, firm contracts rule. And it will come your way. There is no doubt that all the pipelines that Bill Wood and I have discussed it with him many times, there are many reasons why, but one is the increase in electric, and meeting the needs upstream, it is also supply and that changes the dynamics, what gas you can get into California. And with that, I am finished.

COMMISSIONER BOYD: Thank you -- very complex and comprehensive. Any questions? You fooled them all.

MR. TOMLINSON: Yeah.

COMMISSIONER BOYD: All right, thanks very much, Wayne.

MR. TAVARES: Well, thank you very much, Wayne. Just a couple of announcements. We have the Natural Gas

Working Group meeting scheduled for June 4th; again, it is not part of the IEPR proceeding, but it is a semi-annual type of meeting that we have to discuss natural gas issues, still scheduled. We are developing the agenda now and you will get a notice pretty soon. The second one is that we have a Natural Gas Workshop and that will be a Joint IEPR and Electricity and Natural Gas Committee Workshop on June 16th. The topics will be Price Initiatives of Natural Gas, where we will look at some historical prices and the potential factors that actually play in the increase or decreases of prices. The second topic of that June 16th workshop is going to be Potential Impacts of Current prices at the state level and at the federal level. So those two topics will be the main topics for the June 16th. And with that, Commissioner Boyd, that is the only thing we have for today.

COMMISSIONER BOYD: Okay, thank you Ruben. Thanks to the staff --

MR. TAVARES: Oh, public comments, I am sorry.

COMMISSIONER BOYD: Ah hah, you are not done.

MR. TAVARES: Anybody has questions here, or anybody has public comments they want to make? Anybody online?

MS. KOROSEC: All right, we have got the lines open, if there is anybody online who would like to make any comments or ask a question, now is your chance.

COMMISSIONER BOYD: I think you outlasted them all, Ruben.

MS. KOROSEC: All right, well, I think that is it.

COMMISSIONER BOYD: Okay. Thank you, everybody. And I look forward to seeing you or your fellow employees on the 16th of June. Thank you.

[Adjourned.]

CERTIFICATE OF REPORTER

I, Tahsha Sanbrailo, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Joint IEPR and Electricity & Natural Gas Committee Workshop on Natural Gas Activities; and that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 27th day of May, 2009.

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PHILLIP GIOE